

Ultra-Deepwater Production Systems Final Report

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Abstract:

The report herein is a summary of the work performed on three projects to demonstrate hydrocarbon drilling and production methods applicable to deep and ultra deepwater field developments in the Gulf of Mexico and other like applications around the world. This work advances technology that could lead to more economic development and exploitation of reserves in ultra-deep water or remote areas.

The first project is Subsea Processing. Its scope includes a review of the “state of the art” in subsea components to enable primary production process functions such as first stage liquids and gas separation, flow boosting, chemical treatment, flow metering, etc... These components are then combined to allow for the elimination of costly surface production facilities at the well site. A number of studies were then performed on proposed field development projects to validate the economic potential of this technology.

The second project involved the design and testing of a light weight production riser made of composite material. The proposed design was to meet an actual Gulf of Mexico deepwater development project. The various engineering and testing work is reviewed, including test results.

The third project described in this report encompasses the development and testing of a close tolerance liner drilling system, a new technology aimed at reducing deepwater drilling costs. The design and prototype testing in a test well are described in detail.

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INTRODUCTION:

As exploration and production of oil and gas move into deeper water, the need to develop new technologies is becoming increasingly apparent. The cost of surface facilities grows with the water depth, as larger floating platforms are necessary to provide enough buoyancy to support the production and export risers. From a drilling perspective, the superimposition of the sea water pressure gradient down to the mudline over the higher formation gradients below has the net effect of requiring more and more intermediate casing strings to be able to reach target depth.

The Gulf of Mexico ultra-deep waters of 5000 feet to 10,000 feet offer some of the most expensive hydrocarbon basins in the world to find and recover reserves. The reserve size distribution historical statistics in the GOM with exploration drilling in water depths greater than 1000 feet indicate that nearly half of wells drilled find some quantity of hydrocarbon, but that less than one tenth of those are large enough to pay the high cost associated with field development. By halving the minimum economic field size required for development, we quadruple the probability of finding commercial quantities of oil and gas in the GOM.

The three projects described herein are efforts to address some of these issues. They aim to demonstrate hydrocarbon drilling and production methods applicable to deep and ultra deepwater field developments in the Gulf of Mexico and other like applications around the world. This work advances technology that could lead to more economic development and exploitation of reserves in ultra-deep water or remote areas. In some cases, these technologies may be enabling: allowing for economic production where conventional technology simply cannot. Reserves in these areas can add significantly to reducing the United States dependence on foreign oil supplies. Importantly, all three projects are considered as first steps in their respective technology application areas which, once proven, could lead to wide industry uptake and expansion of their applicabilities.

The three technologies covered under this DOE grant are subsea processing, composite production riser and close tolerance liner drilling. Subsea processing aims at eliminating the requirement for surface facilities in deep waters by allowing for long distance subsea tiebacks to existing shallow water facilities, or directly to shore. The use of light weight and high strength composite material to manufacture deepwater risers would substantially decrease the required tonnage for a floating platform. Close tolerance liner drilling is an adaptation of a highly successful land casing drilling technology to subsea drilling operations, with a high potential to dramatically lower deep water drilling costs and mechanical risks.

EXECUTIVE SUMMARY:

Subsea Processing

Three site evaluations were made to a level of accuracy sufficient to move them to the project funding investment decision level. Two sites were in the Gulf of Mexico, in the vicinity of the Magnolia field, in 4,700 ft of water. The third site was offshore Norway, in only 400 ft of water, but much more remote from any existing facility. Unfortunately, none of these locations would support a positive investment recommendation after risking these prospects was done.

The first site was approximately five miles west of Magnolia Field in 4700' of water and required four wells, one pipeline for gas, one pipeline for oil / water stream, the sub-sea process and all associated flowlines and umbilicals for control, power etc. The overall cost estimate for early feasibility economics indicated a capital cost estimate of more than two hundred million dollars to install. The geologic setting in this area is very complex. The risk model available during the study phase of this site was applied to the capital cost estimates done as part of this feasibility effort. The geologic complexity proved too risky for investment managers to support further engineering efforts to move this project forward.

The second evaluation was done on an offset to the main Magnolia Field in GB 784. Work was completed here to show that tieback to Magnolia did not economically justify further investigation based on currently available data. Early views of reserves accumulation size and fluid characteristics have been modified significantly with new seismic data and associated interpretation. This new information indicates the much higher likelihood that the reservoir is gas whereas prior interpretations of existing data indicated oil. The accumulation size across the full range of reserve possibilities was also reduced. Conversely, drilling and completion cost estimates were also increased.

The sub-sea separation and pumping equipment necessary to operate in these water depths and with these fluid characteristics are currently available on the market and application of this technology need only meet economic hurdles to be applicable. Soon after completing this evaluation another opportunity to apply subsea processing in Norway arose. In this case, water depth was only 400 ft, but a subsea development would have required a 60 miles subsea tieback. This in turn required subsea processing and boosting to be achievable. The subsea processing option was compared to the base case of a fixed platform or FPSO, and proved economically very attractive. However, the operator decided against subsea processing due to lack of previous experience and confidence in the technology (the “first mover” syndrome).

Composite Production Riser

A Joint Industry Project was conducted over a two-year period, starting in March 2003, to develop a composite production riser joint design qualified for deployment on the Magnolia tension leg platform in the deep waters of the Gulf of Mexico. Once the design was qualified, the JIP planned to manufacture a limited number of composite joints for insertion in one of the Magnolia steel risers, and monitor their performance over the service life. The objective of this demonstration was to gain industry acceptance for this new composite technology application, with the expected benefit of lowering future deepwater field development costs thanks to the significant riser weight reduction.

The Magnolia steel production riser is a nominal 11 ¾" diameter, 10,000 psi working pressure system, in 4,674 ft of water (the world's deepest for a tension leg platform). Because of this water depth, the riser axial load design criteria are very stringent. However, the proposed composite joint design was shown to easily meet this axial load requirement, with a **2400 kips** tension test: the test equipment actually failed before the composite joint. It should be noted that a design for a full composite riser, as opposed to a steel riser with a few composite joints, would be much less demanding as far as axial loads are concerned.

The burst design took more effort due to the difficulty of accurately predicting the performance of carbon fiber hoop layers of slightly irregular geometry, using a computer based finite element analysis. After some model fine-tuning and design modifications, a burst test of **25,716 psi** was eventually achieved.

Importantly, the real design challenge was not with the composite itself, but with the associated steel and rubber components. Indeed, a composite joint is not entirely made out of composite material. Steel end connectors are required to make up the joints in the string. Also, the composite matrix is permeable, requiring a separate pressure barrier for containment. This is provided by a steel liner in-between the two steel end connectors. The steel liner also serves as a mandrel around which the structural composite is wrapped. In order to maintain the benefit of the lightweight composite, the liner obviously needs to be kept as thin as possible (0.165" wall in this case). As such, it is vulnerable to gouging by drilling tools run through the riser. It was therefore decided that this inner steel liner had to be backed up by a secondary pressure barrier in the form of a rubber or steel sheet wrapped around the inner liner before applying the composite. A major portion of the development work was expended on the reliability of the inner liner welds and secondary pressure barriers.

The JIP work also included evaluation of various systems for long term, underwater, monitoring of the composite material performance. After extensive testing, two promising strain sensor types, in the form of magnetic metal patches, were selected to be embedded in the field joints.

After obtaining conditional regulatory approval for the design, five 63 ft long field joints were fabricated for installation on Magnolia. Unfortunately, factory acceptance testing of the

field joints uncovered defects in the steel liner welds and secondary barrier seals. These reliability concerns led to cancellation of the proposed field deployment, as there wasn't sufficient time left to fabricate additional joints. It is the project participants' opinion that these issues can be fully resolved in a short time, through optimized steel material selection, automated welding processes and improved NDE procedures.

The project was still very successful in advancing the composite riser technology, to the point it can be brought forward to a field application with very little additional work. Among the most notable achievements are:

- 1) A Finite Element Analysis (FEA) model has been developed and validated to the point it can now be readily used as a design tool for future composite riser applications.
- 2) A new composite fiber lay-up design has been developed and demonstrated to increase axial load capacity by 40% over those used in previous projects, using the same metal part geometry and axial fiber thickness.
- 3) A system to monitor the performance of the composite material in service has been qualified and can be made available for offshore deployment within the time frame of a future project.
- 4) A large amount of test data has been collected, leading to a better understanding of stress distributions between structural composite and steel components.

Close Tolerance Liner Drilling

Drilling with casing, instead of drill pipe, is a very successful technology that has recently gained acceptance for onshore applications. This project aimed at adapting this technology to the deepwater environment. When drilling subsea with casing, the casing has to be hung at or below the mudline. It is carried there by drill pipe back to surface. Therefore, when drilling subsea with casing, a tapered string consisting of casing and drill pipe needs to be used, and the operation effectively becomes equivalent to drilling with a liner carried by a drill pipe running string.

The scope of this project consisted in the development and testing of a 11 3/4" liner drilling system to be run through a 13 5/8" casing. This size combination was chosen as the first target application because it is likely to provide the largest initial benefit in deepwater applications. Other sizes can be "scaled" for future tool development.

The primary components of the system are 1) the liner hanger, 2) the liner hanger running tool, 3) the dynamic casing seal assembly, and 4) the liner itself. After completing the detailed design, each of the components was built and tested individually, then the system was assembled and tested in both cased and open hole.

All component testing was highly successful. Fatigue was shown not to be an issue with the liner connections selected. The dynamic casing seal assembly was durable and resistant to wellbore fluids and temperatures. The primary components within the liner hanger running tool proved to be resistant to erosion from the circulation during drilling.

The system test was largely successful. The system functioned and tested as designed. During the cased hole testing, the system was thoroughly tripped and rotated: in all respects, simulating an open hole drilling program. It was pulled and examined for wear, and very little was found. However, some internal seals had failed, and that allowed mud to broach the inner assembly. Modifications were made to prevent this in the future and the tool was re-deployed for the open hole test.

In the open hole test, the system was used to drill nearly 300'. It was pulled after the liner became plugged with gumbo. This would not be an issue in the offshore environment where synthetic muds are used to completely eliminate gumbo.

In January, 2004, it was determined that ConocoPhillips's target deepwater drilling rig, the Transocean Deepwater Pathfinder, was to be released by ConocoPhillips before the liner drilling testing was completed. The project was therefore suspended after the open hole test.

In conclusion, the close tolerance liner drilling system works. Minor mechanical enhancements have been identified that must be incorporated to prevent damage from severe vibrations as the test system experienced, and operational changes were developed to avoid the vibrations altogether.

RESULTS AND DISCUSSION:

SUBSEA PROCESSING

In deepwater developments, approximately one-half of the costs are associated with drilling, and the other half relate to the facilities necessary to produce and transport the hydrocarbons. While floating production platforms offer the advantage of accessibility, they bring several disadvantages.

- These facilities cost from several hundred million to well over one billion dollars.
- This tremendous investment is initiated years prior to first production.
- They are not easily modified to accommodate changes in production.
- They are manned, introducing safety risks to personnel.
- They are not easily re-used in multiple locations.

The vast majority of the investment is in the structures, risers, moorings, etc., necessary to physically support the production equipment. The investment in the production equipment itself is relatively minimal. This has motivated industry to advance subsea processing technology (SSP). With SSP, nearly all equipment that is ordinarily on the production platform is placed on the seabed. Some of the key advantages are:

- The facilities cost can be reduced by 80% or more. This significantly reduces minimum economic field size (MEFS).
- Delivery times are significantly reduced, hence deferring the investment until much closer to first production.
- Project cycle time from discovery to first-production can be significantly shortened.
- The facilities are unmanned.
- The production facilities are compact, and “plug and play”, allowing for change-out of the facilities as the field’s production requirements change.
- The facilities are closer to the reservoir, allowing for lower abandonment pressures and greater reserves.
- Operating costs are much lower, allowing for longer field life and greater recovery.
- Field abandonment costs are reduced.

Several SSP modules have already been developed, including separators, pumps, compressors, pigging facilities and others, along with a guideframe that can receive these modules. The design offers the ability to change modules out for repair, or for reconfiguration due to increased water cut, or increased gas cut, or to address most other needs that a field might have over its lifetime.



FIG SSP-1



FIG SSP-2



FIG SSP-3

Export from the field can be through pipelines or flowlines to nearby fields, or to a floating tanker for oil storage, or in some cases, all the way back to shore. Produced water can be cleaned and discharged, or directly injected into another well from the seabed unit. Power and controls can be provided from a nearby host facility, floating power buoy or surface oil storage vessel. There are very few limitations as to the utility of the SSP facilities.

The advantages and flexibility of SSP clearly demonstrate that this is an enabling technology for the exploitation of smaller reservoirs, and an enhancing technology for the development of larger reservoirs. Yet, industry uptake has been limited.

In order to bolster industry confidence in this technology, a program was undertaken to finish the development and complete a formal feasibility design for application and possible demonstration in a deepwater environment. The design objectives were to prove technical feasibility for an SSP system in water depths to 10,000 feet, and at a distance of up to 50 miles from a host facility. Even though the capital cost of such an installation would be much less than that given a conventional development, the subsea development including drilling of one or more subsea wells, installing subsea pipelines and service umbilicals might cost upwards of \$200MM. In order to compete with conventional technology in any deepwater development opportunity, the first step was to ensure technology gaps for SSP were identified and resolved and that specific deepwater locations and data sets at these locations were used for credible comparisons to conventional solutions. All project participants shared the cost of this first step equally so that this new technology could be provided as a realistic alternative that would render an otherwise uneconomic venture economic and viable.

Three locations were investigated. Two were in the Gulf of Mexico in approximately 4700' of water. In one case, the design called for a 33,000 BOPD SSP system with separate liquid

export and gas export to a nearby facility. Power and control would come from that facility. The second system was similar in design but rated for 20,000 BOPD.

The first site was approximately five miles west of Magnolia Field in 4700' of water and required four wells, one pipeline for gas, one pipeline for oil / water stream, the sub-sea process and all associated flowlines and umbilicals for control, power etc. The overall cost estimate for early feasibility economics indicated a capital cost estimate of more than two hundred million dollars to install. The geologic setting in this area is seismically very complex with very steeply dipping structures due to salt induced fracture systems over the area of potential development. The unrisks reserves ranged from 50 to 200 million barrels of oil recoverable. On an unrisks basis, this was shown to be economically viable. The risk model available during the study phase of this site was applied to the capital cost estimates done as part of this feasibility effort. Once the risks associated with altering the host facility to accept the regional tie-in, with increased well count and expense due to reservoir compartmentalization, and the added geologic risk of a reservoir seal due to the underlying salt dome induced fracture system, the opportunity failed to meet fully risks economic hurdles.

The second evaluation was done on an offset to the main Magnolia Field in GB 784. The main Magnolia project development plan did not include this offset because it was too far away and too risky to drill to three miles from the tension leg platform location. Early views of reserves accumulation size and fluid characteristics were modified significantly with new seismic data and associated interpretation. This new information indicated the much higher likelihood that the reservoir is gas whereas prior interpretations of existing data indicated oil. The accumulation size across the full range of reserve possibilities was also reduced.

One of the cost elements, namely the drilling and completion cost, was significantly increased also after a February 2002 peer review. It was agreed that, because of the structural complications associated with these reserves in 784, the production well cost of approximately forty million dollars for drilling and completion would require a sidetrack step out about three years after first production in order to produce the remaining forty percent recoverable reserves now indicated. The sidetrack added some thirty million dollars to the well cost. After reserve size and hydrocarbon types were evaluated, work was completed here to show that tieback to Magnolia did not economically justify further investigation, as all cases in the P10/P90 range of outcomes were sub-economic based on currently available data.

A third field development evaluation, in the Norwegian Sector of the North Sea, showed benefits in much shallower water (400') but the advantage here was due primarily to lower initial CAPEX vs. FPSO or platform. Another benefit in this example was enhanced flexibility to pump liquids over 60 miles away to one facility and send the separated gas to a nearby gas processor station about 10 miles away. This development is still under evaluation by the operator.

Despite the negative economic evaluations, there was sufficient technical work done to confirm that there are no technology gaps remaining for the SSP system. All that remains now is more field demonstration to help assuage the perceived risks associated with SSP.

COMPOSITE PRODUCTION RISER DEMONSTRATION

INTRODUCTION AND BACKGROUND

As exploration and production of oil and gas move into deeper water, weight, cost, and reliability of water-depth sensitive systems such as risers become increasingly important. Composite materials offer several attractive properties, such as high specific strength and stiffness, lightweight, corrosion resistance, high thermal insulation, high damping (reducing vortex-induced vibrations concerns), and excellent fatigue performance, making them a good candidate for deepwater risers. In addition, the use of composites permits greater design flexibility for tailoring properties to meet specific design requirements, thus promoting better system-oriented and cost-effective solutions. Capitalizing on these advantages for composite riser applications results in lower system cost (reduction of riser weight decreases platform size and riser tensioners) and higher reliability for deepwater developments. Therefore, major efforts have been devoted during the last few years to assess the potential of composite materials for deepwater riser applications.

Design and qualification of composite risers have been the subject of three recent joint industry studies. Composite production and low-pressure drilling risers with elastomeric liners have been developed by joint-industry projects that were initiated in 1995 and were partially funded by the U.S. Department of Commerce National Institute of Standards and Technology (NIST) Advanced Technology Program. High-pressure composite drilling risers have been developed as part of a joint industry project organized by Norske Conoco A/S, Kvaerner Oilfield Products, ChevronTexaco, Shell and Statoil, and partially funded by the EU Thermie. A 22" high pressure composite drilling riser joint has been in operation since July 2001 at the Heidrun TLP. The details on the NIST and Conoco/Kvaerner programs and many results have been extensively published.

The composite riser programs involved design, manufacturing, and testing of many full diameter joints under different loading conditions. The NIST Composite production riser program involved testing more than 80 full diameter (10 3/4") joints under conditions of static, creep, and axial fatigue. The composite drilling riser program involved testing four full diameter (22") joints under conditions of static, fatigue, and impact. The key conclusion of all these tests is that the current state of practice of the composite industry is robust enough to allow reliable design and manufacturing of composite risers.

In spite of this high level of interest in composite risers and the large business opportunity, the commercial application of composite risers remained tentative because of uncertainties associated with the difficulty of introducing new technology. This difficulty arises from emotional and perceived technical barriers in addition to serious concerns regarding potential escalation of cost and delays in schedule. It is believed that these barriers are generally removed after the first use. As a means of addressing the first use issue, a Joint Industry Project was formed in March 2003 by ChevronTexaco, ConocoPhillips and Kvaerner Oilfield Products, a group later joined by Total, to qualify several 11-3/4" composite production riser joints for installation on the Magnolia tension leg platform in the Gulf of

Mexico. This project was also partly funded by a grant from the United States Department of Energy National Energy Technology Laboratory.

The Lead Contractor for the design and fabrication of the composite joints was DeepWater Composites AS, a company established and jointly owned by ConocoPhillips and Kvaerner Oilfield Products. Other main contractors involved in the project included:

C4PO (Sacramento) – *component testing, composite manufacturing*
SMI/PK Manufacturing (Houston) – *MCI machining and steel liner welding*
DrilQuip (Houston) – *threaded connectors and pipe welds*
ABB-Lummus (Houston) – *Magnolia project engineering contractor*
Stress Engineering (Houston) – *design verification testing*
DNV (Oslo/Houston) – *risk analysis and design review*
Inspection Associates (Houston) – *on-site inspection services*

In addition to the qualification of the proposed design and fabrication/installation of several field joints, the project included an evaluation of in-service inspection methods that have the potential of being monitored remotely or by an ROV. The ultimate objective was to prove the technology in the Gulf of Mexico deep water and obtain actual performance data for application to future developments.

DISCUSSION

1. Magnolia Production Risers Description

The Magnolia TLP is designed to be installed in the Garden Banks Block 783 in the Gulf of Mexico. Approximate water depth at the platform location is 4,674 feet, a new world record for a TLP. Production wells (up to 9) are tied back to the TLP from the subsea wellhead utilizing an 11 3/4" OD production riser with a 4-1/2" production tubing inside. During normal production operations, well fluids will be flowing through the tubing, with the 11 3/4" production riser providing environmental protection and a second fluid barrier. The riser/tubing annulus is normally filled with low pressure Nitrogen, subjecting the riser to collapse pressure from seawater hydrostatic. Completion, future workovers and potential sidetrack activities requiring removal of the tubing will be conducted through the 11 3/4" production riser and a surface blowout preventer. In this mode, the production riser then becomes a primary pressure containment barrier and must meet a 10,000 psi burst rating. The production riser bore may be exposed to the whole range of producing, completion and drilling fluids, such as oil, gas (no H₂S), high density brines, drilling muds. It will also be subjected to possible wear and tear from rotary drilling activities. This wide variety of service conditions makes this project ideally suited for proving the composite riser technology.

The Magnolia production wells have been pre-drilled by a deepwater semisubmersible drilling rig and were temporarily suspended at the subsea wellhead until TLP installation. The production riser is latched onto the subsea wellhead at the seabed elevation, and extends through the water, splash zone, air gap, and terminates in the well bay at the surface (dry) tree. A tensioning system supports the riser from the tree deck (Fig CPR 1). The riser is installed and removed from the platform, by a workover/completion rig. Interfaces relevant for the composite riser joints are the connections to steel joints, as well as installation and handling issues.

The principal specifications for the Magnolia production riser steel joints are:

Outside Diameter:	11.750"
Nominal Wall:	1.014" (9.722" nominal ID)
Approx. Weight:	122 lb/ft
Material Strength:	85 ksi (both pipe and connectors)
Connector Type:	threaded pin and box (DrilQuip PR-85)
Joint Length:	62.75" (made-up)
Working Pressure:	10,000 psi
Test Pressure (Factory):	11,250 psi
Max. Top Tension:	1316 kips (no buoyancy)
Service:	No H ₂ S
Design Life:	20 years

The Magnolia Project has established a detailed Basis of Design document for the steel risers, which includes an exhaustive listing of all design load cases. Another document provided by Magnolia is the Scope of Work for the fabrication of the steel riser joints, which details their technical and QA/QC specifications. Both were “translated” into similar documents for the composite riser design and fabrication. The composite riser joint design must adhere to the same criteria as the Magnolia steel riser joint. Operationally, it is designed to be inserted in-between two steel joints, using the same threaded connector. Also, it needs to be configured such that it can be picked up and made up on the rig floor using the same equipment and procedures as for the steel joints.

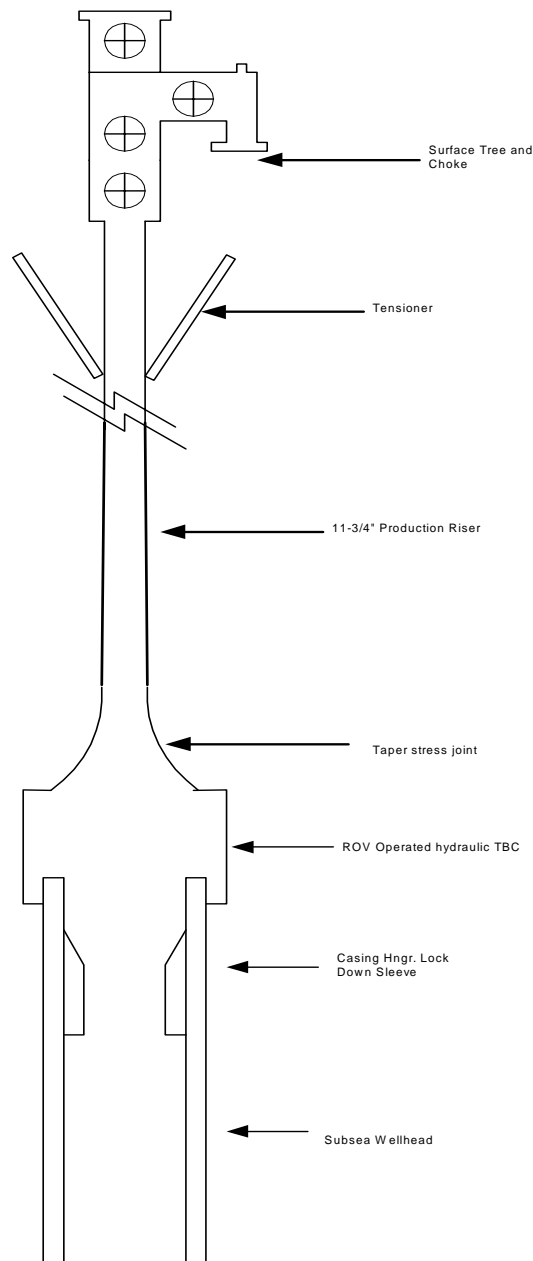


Fig. CPR 1 – Magnolia Production Riser Schematic

2. Initial Composite Joint Concept

The basic concept of the Magnolia composite production riser joints is similar to that used in a high-pressure composite drilling riser joint currently in use on the Heidrun TLP in the North Sea.

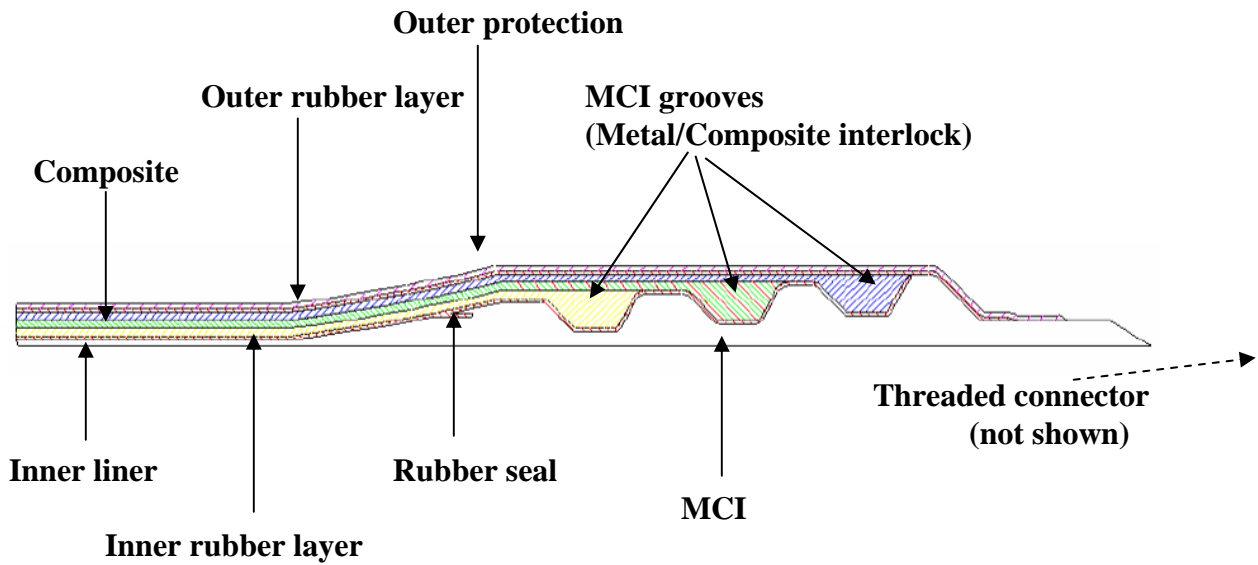


Fig. CPR 2 – Composite Production Joint – End Fitting Concept

The preliminary composite production riser joint concept consists of the following component parts (see Fig CPR 2):

Inner liner: A thin (0.165" wall) steel inner liner is used as a gas permeability barrier. The liner is welded at both ends to the steel MCI fittings. During production operations, the annulus is normally filled with nitrogen, and no corrosion allowances are needed. In the workover/drilling mode, the steel liner also protects the next layer (rubber) from tear due to drilling tools movements.

Rubber layers: A rubber layer (HNBR) between the inner steel liner and the composite body is applied as the secondary seal. For this purpose, a seal needs to be incorporated at the MCI end. This seal needs to be designed to hold pressure applied in-between the steel liner and the rubber liner. The inner rubber layer also serves as "shear ply" for the subsequent composite layers. An outer rubber layer is also used as the external liner, to prevent water ingress into the composite body. Both rubber layers extend to the outboard of the MCI traps.

Composite body: Carbon fibers in axial and hoop directions together with an epoxy resin system will be applied as the structural composite laminate.

Outer protection: Glass fiber and epoxy resin composite is used as a compaction wrap and scuff protection layer over the external rubber jacket. Additional protective material can also be wrapped around the finished joint.

Metal Composite Interface (MCI): Loads applied to the steel connector extensions are transferred into the Structural Composite Overwrap (SCO) through the grooves in the MCI. MCI geometry and construction result in a true mechanical interlock between the SCO and fitting, with all load transfer through bearing between composite and metal surfaces. Axial fiber layers are run through the MCI grooves and locked in place by a number of hoop layers, thereby gripping them. The concept is roughly similar to that of a rubber hose end fitting.

Threaded connectors: The end connectors will be identical to the ones selected for the steel joints. This means that a composite joint can be directly inserted between two steel joints, without any adapter. The connector can be either fabricated in one piece with the MCI, from a longer forging, or a separate “off the shelf” connector that can be welded on the outboard of the MCI.

3. Risk Analysis

Prior to initiating work on the design of a composite joint for the Magnolia application, a risk analysis was performed based on the above basic concept. The objective was to determine whether the Magnolia Project would be subjected to any additional risk with the placement of a number (up to ten) of composite joints in one of its production risers, and to identify potential operational problems stemming from this new technology application.

Det Norske Veritas was contracted to conduct this study. The Failure Modes and Effects Analysis (FMEA) methodology was followed by a joint team of ConocoPhillips and DNV personnel to systematically review all potential failures for all modes of operation (installation, well completion, production and drilling/sidetracking). Once the failure modes were identified, the team quantified the risk by assessing it in comparison to the risk exposure from the use of all-steel risers only. The risks are assigned a severity rank (one to five) based on the team’s assessment of the potential impact on four distinct aspects: personnel safety, environment, remedial cost and effect on corporate/industry reputation. Similarly, failure modes are ranked by estimated frequency using industry statistics, also from one (never heard of) to five (several times per year). The two rankings, severity and likelihood, are then combined in a matrix for an overall risk classification (low, medium or high).

In the **installation mode**, the main concern identified was the possibility of damage to the outer protective layer to the extent that the outer rubber liner would be breached. This would allow seawater hydrostatic pressure to be transmitted to the inner steel liner. At the time the FMEA was performed, a design analysis was not yet available, and the collapse resistance of the steel liner within the composite structure was not known. Although the steel liner alone has fairly low collapse resistance (1264 psi), the fact that it is constrained by the surrounding composite makes the evaluation fairly complex. The FMEA identified

this issue as requiring evaluation and qualification testing. In any event, it was estimated that impact damage was most likely to occur during surface handling and could be easily detected visually.

During **well completion**, drilling operations are actually taking place (to drill out temporary abandonment cement plugs). The issue then is potential gouging of the steel liner up to the full wall thickness, and possibly beyond, damaging the rubber liner as well, with consequent loss of pressure integrity. It was also observed that the inner rubber seal could not be tested independently of the steel liner. The FMEA recommended looking at drilling equipment and procedures to mitigate this risk, as well as acceptance criteria for future caliper logs measuring any loss of wall thickness.

In the **production mode**, the same issue of potential steel liner collapse due to breach of outer rubber seal was again highlighted. It was also determined that a leaking liner could locally buckle in a fast depressurization event. This could happen during a riser pressure test for instance, if a small leak (crack) occurs through the steel liner allowing high pressure fluid to separate the inner rubber layer from the steel and create a “micro-annulus”. Upon release of the internal pressure, the fluid in that annulus may not be able to escape fast enough, resulting in locally excessive pressure differential. This phenomenon was recorded in a previous project, where a crack in the inner metal liner resulted in the discovery of local inward bulges after a high pressure test. Although this may not result in loss of pressure integrity, it will cause a loss of drift ID. The FMEA suggested the insertion of a permeable layer between rubber and steel to allow the annulus fluid to escape, as well as controlling depressurization rates. This concept would have to be tested (see “Cracked Liner Tests” in the following sections).

In the **drilling mode**, the same risks regarding deep gouging of the inner steel liner were identified, as in the completion mode. However, the potential consequence would be more severe, as the riser would then function as a single barrier with the well bore potentially exposed to uncased productive formations.

One general issue also raised by the FMEA is the lack of a reliable method for in-service inspection of the composite material itself. Evaluation and possible development of such methods should be considered by the project.

In the case of a new technology application, one difficulty is the lack of actual reliability data to determine failure mode frequency. The analysis relies on experience with similar components (seals, connectors), material performance in other applications and expert evaluation. After reviewing the failure mode listed above, as well as mitigation measures, the failure rate for a leak through the composite joint body has been assigned a highly conservative value to account for all uncertainties. The FMEA also pointed out some

aspects where the composite joint design is superior to steel, such as reduced Vortex Induced Vibration (VIV) and the ability to independently address axial and burst designs.

In conclusion, the FMEA determined that the inclusion of ten composite joints in one of the Magnolia risers would not significantly increase the risk exposure, provided that strict acceptance criteria be adhered to with respect to the outer protection impact damage and inner steel liner caliper logs. Also, to eliminate platform personnel exposure to gas fire risk in case of catastrophic failure, the joints should be installed at least 600 ft below sea level. Along with the Magnolia steel risers design basis, this FMEA is an important reference document for the design and testing of the composite joints.

4. Original Design

The design phase was started after the FMEA was completed. In order to evaluate the composite performance under various conditions, it was decided that the composite joints would be installed at two different levels in the riser string: one batch around 1,000 ft water depth, one around 3,000 ft, with each batch consisting of up to five joints. The 1,000 ft is simply an added safety factor to the 600 ft determined by the FMEA. The 3,000 ft was chosen because it was the depth limit for the acoustic current monitoring system. In any event, the bottom five joints above the stress joint need to be steel due to more severe drilling wear. After adding preliminary safety factors over steel riser criteria, the initial design basis for the composite riser joints called for meeting the following acceptance parameters:

Tensile:	2,500 kips
Burst test:	22,500 psi
Collapse Test:	2,500 psi
Fatigue life:	1,000 years

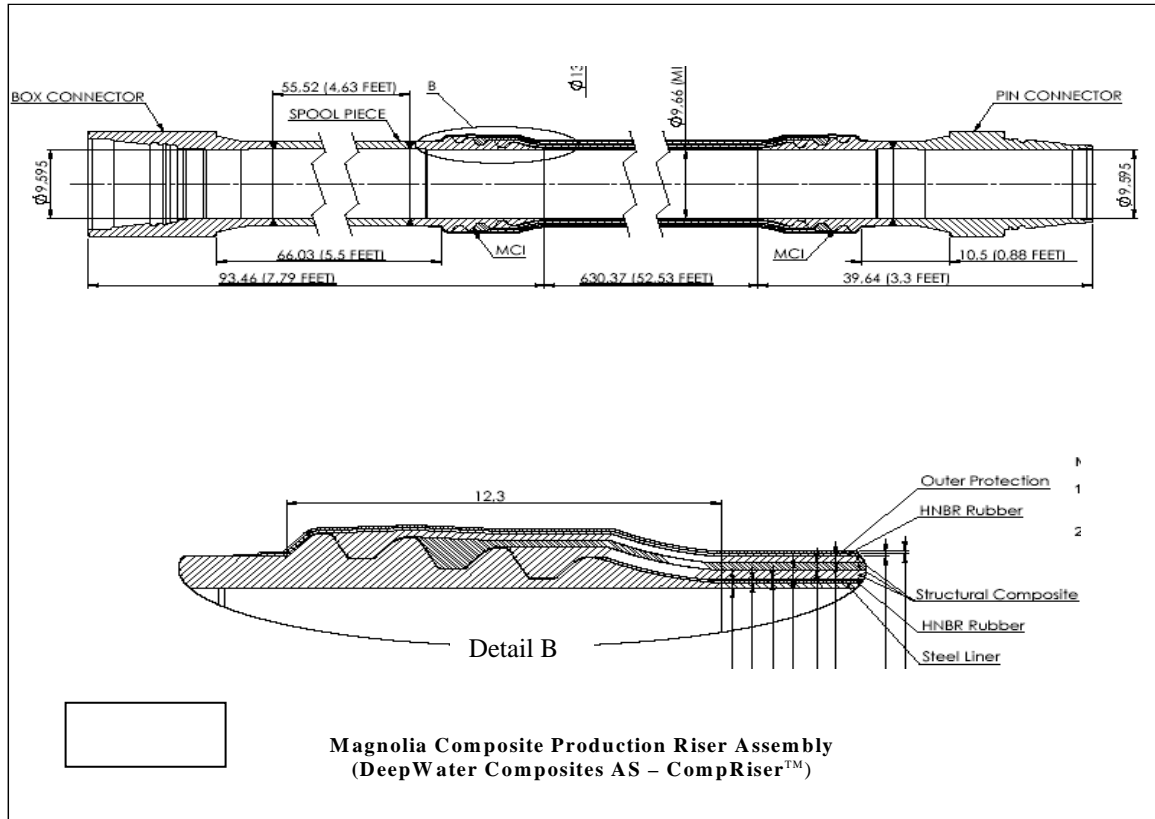


Fig. CPR 3 – Original Magnolia CPR Design

The steel riser installation equipment and procedures were reviewed for compatibility with the composite joint design. In order to accommodate the split spider system used to hold the string at the rig floor level, it was established that a 4 ft length of steel riser pipe had to be inserted between MCI and box connector. This would allow for landing the box onto the spider while spacing out the large OD MCI below (See Fig. CPR 4). It also provides space below the box to latch elevators.

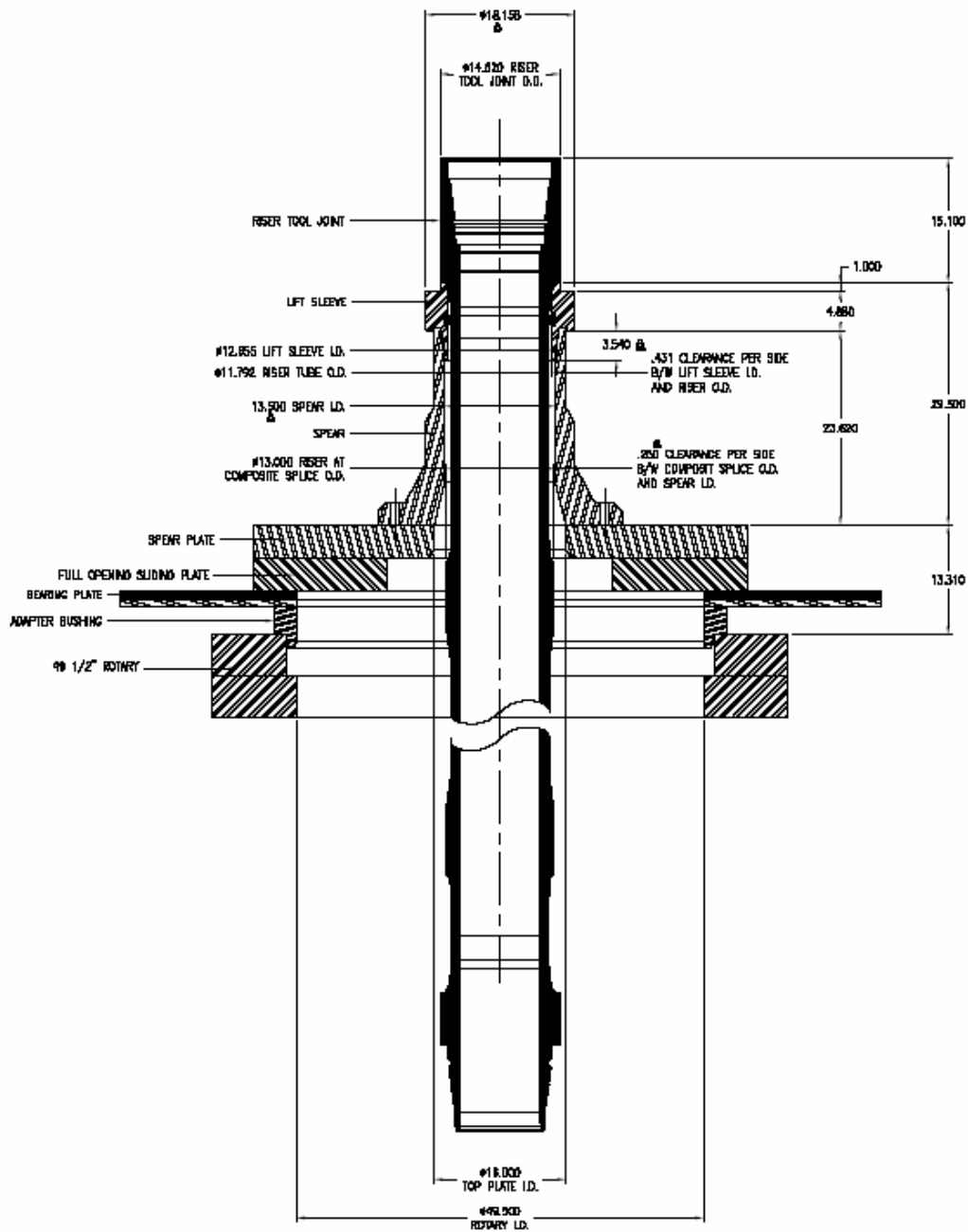


Fig. CPR 4 – Composite Joint Hung on Spider

Another installation consideration was a desire to minimize the outside diameter of the MCI. A 3-trap MCI configuration was initially selected for analysis.

In order to ensure material compatibility with the steel riser connectors and pipe welding procedures, the MCI will be made out of the same forged material (A707 – 85 ksi) as the

connectors. Due to availability and overall schedule constraints, these forgings, along with the threaded connectors, were ordered at an early stage of the design.

Procurement of the steel liner material was another issue, due to limited availability of the required size and grade. After other alternatives had to be rejected due to cost and delivery constraints, pipe made out of cold rolled 93 ksi steel plate was purchased from Valmont. The 0.165" thick plate was rolled to a 10" OD. This comes in 40 ft long sections, requiring an extra weld to fabricate the length required for a full field joint.

Over this period, DeepWater Composites produced component drawings, engineering and procurement specifications for the original design. An independent consultant (Grover Engineering Mechanics) was contracted to perform a Finite Element Analysis based on a preliminary structural composite laminate design, as follows:

<u>Thickness – in.</u>	
Steel liner	0.165
HNBR liner	0.090
Hoop fibers	0.060
First trap:	
Axial fibers	0.045
Hoop fibers	0.060
Axial fibers	0.045
Hoop fibers	0.060
Axial fibers	0.045
Hoop fibers	0.060
Second trap:	
Axial fibers	0.045
Hoop fibers	0.030
Axial fibers	0.045
Hoop fibers	0.030
Axial fibers	0.045
Hoop fibers	0.030
Third trap:	
Axial fibers	0.045
Hoop fibers	0.030
Axial fibers	0.045
Hoop fibers	0.030
Axial fibers	0.045
Hoop fibers	0.030

All axial and hoop fibers were of 33 msi modulus, except hoops inside the traps (55 msi).

The FEA model simulates the stresses in both steel and composite through the manufacturing and factory acceptance testing process before checking the maximum

operational load cases. The manufacturing process includes an oven curing cycle for the composite and the acceptance pressure test results in actual yielding of the inner steel liner. Both produce residual stresses that have to be accounted for in the FEA. In particular, it is important to note that after the 11,250 psi FAT (two pressure cycles), the steel liner yields, but its strains are constrained by the stiffer composite body. It is therefore left in a compressed state.

This FEA showed that the proposed design would satisfy the worst case loading conditions. It predicted a burst failure at over twice the FAT pressure, or 22,500 psi. The predicted failure mode was either through yielding of the first trap steel, or composite failure (the large plastic deformations at this level prevented the model from predicting which of the failure modes would occur first). In tension, the predicted failure mode was through composite interlaminar shear in the traps, starting at 2570 ksi.

Based on the FEA results, fabrication of test samples could proceed. However, qualifying of the welding procedure for MCI to liner weld proved more challenging than expected, and resulted in a significant project schedule slippage. The low alloy/work hardened material characteristics of the liner made it difficult to control both the extent of the heat affected zone and the resulting mechanical properties (lower yield stresses in the HAZ). Numerous samples were welded and tested, all using copper backings, and various welding processes. The required properties across the girth weld were eventually achieved using a GMAW (Gas Metal Arc Welding) process.

5. CLT-1 and First Design Revision

The first test sample, CLT-1, was fabricated by C4PO for a “cracked liner test” to address some of the issues raised in the risk analysis. The objective of the test was twofold:

- a) Measure the benefit, if any, of having a permeable layer in-between the steel liner and the inner rubber layer. The test called for manufacturing a thin, longitudinal crack inside the steel liner, then pressuring up the joint to 10,000 psi, forcing water through the crack. The joint would then be depressurized slowly and checked for inner liner buckling. The pressurization/depressurization cycles were to be repeated, with increasing bleed-off rates until buckling was observed. The crack is cut longitudinally as this would be the case for gouging by running or pulling drilling tools through the riser.
- b) Validate the rubber seal for 10,000 psi.

CLT-1 was actually manufactured without a permeable layer. The idea was that a second sample (CLT-2) would be fabricated next, this time with a permeable layer, and the two tests would be compared.

Given the test objectives, CLT-1 was not fabricated to the same standards as a design verification joint. In particular, locally available 4130 steel was used for the MCI's, instead of A707 forged material. The test joint was 20 ft long, with test flange connections at each end, and MCI and composite geometries as used for the original FEA. A number of strain monitors were fitted to the outer layer to record the strain behavior over the multiple pressure cycles. Additionally, prototype "Trip Metal" sensors from StructureMetrix were also installed, to assess the potential for this technology to perform in-service monitoring of the composite. See Fig. CPR 5.



Fig. CPR 5 – CLT-1 Sample

made to maintain the pressure up around 11,250 psi with the test pump, in order to detect the location of the leak. At that stage, the test joint failed in burst.

The test sample was taken through the Factory Acceptance Test (FAT) procedure. This consists of two pressure cycles to 11,250 psi. The first one has a short holding period for the "autofretage", during which the steel and composite take their permanent set relative to each other (the steel liner yields), and is in effect part of the manufacturing process. Fig. CPR 6 illustrates the effect of autofretage on the length of a 10-ft long test joint over the two initial pressure cycles. The second cycle verifies pressure integrity of the final product.

The autofretage took place uneventfully (although subsequent analysis of test data and comparison with other tests indicate that the metal may have already failed during this cycle). During the second FAT pressure cycle, the joint started leaking through the composite near the test pressure. An attempt was

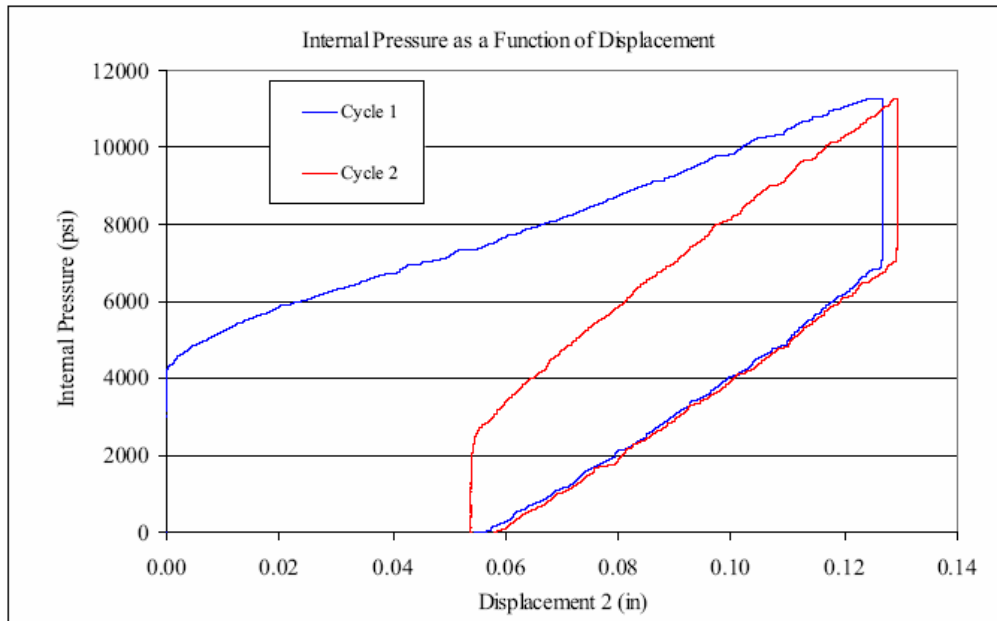


Fig. CPR 6 – Autofretage Effect on Joint Elongation (10 ft Test Sample)

The failure appears to have initiated in the vicinity of the MCI/Liner weld, then propagated up the MCI ramp, with the composite failing around that area (Fig. CPR 7). Also notable, is the fact that the sudden depressurization of the bore caused buckling (bulge) of the steel liner, as would be expected.



Fig. CPR 7 – CLT-1 Burst Area

Even though the failure initiated in the metal part, the composite should have been able to contain the burst stresses, although the cutting action of the metal “lips” along the fracture may have weakened the inner hoop fibers and precipitated the composite failure. Still, this

incident prompted a review of the FEA. It then became apparent that the wrong allowables (not accounting for resin volume in the laminate) were used in the model. This resulted in a first design revision, namely an increase in the thickness of the hoop layers.

6. Backup Rubber Seal Issue – CLT-2, 3 & 4

A CLT-2 sample was then fabricated, similar to CLT-1, but with the revised composite lay-up, and including a permeable layer consisting of dry fibers in-between the steel and inner rubber liners. Also, instead of locally manufactured flanged end connections and MCI, regular test sample metal end assemblies (MCI and ACME box) fabricated by SMI/PK in Houston were used.

The sample was subjected to the two FAT pressure cycles without incident. A narrow longitudinal groove was then machined into the steel liner (Fig. CPR 8). The depth of the groove (approx $\frac{3}{4}$ of liner wall thickness) is enough to initiate a full penetration crack at a pressure significantly below the 10,000 psi test pressure called for in the cracked liner testing procedure. The expectation is that the crack will open at the bottom of the machined groove while the sample is going through the next pressurization cycle.

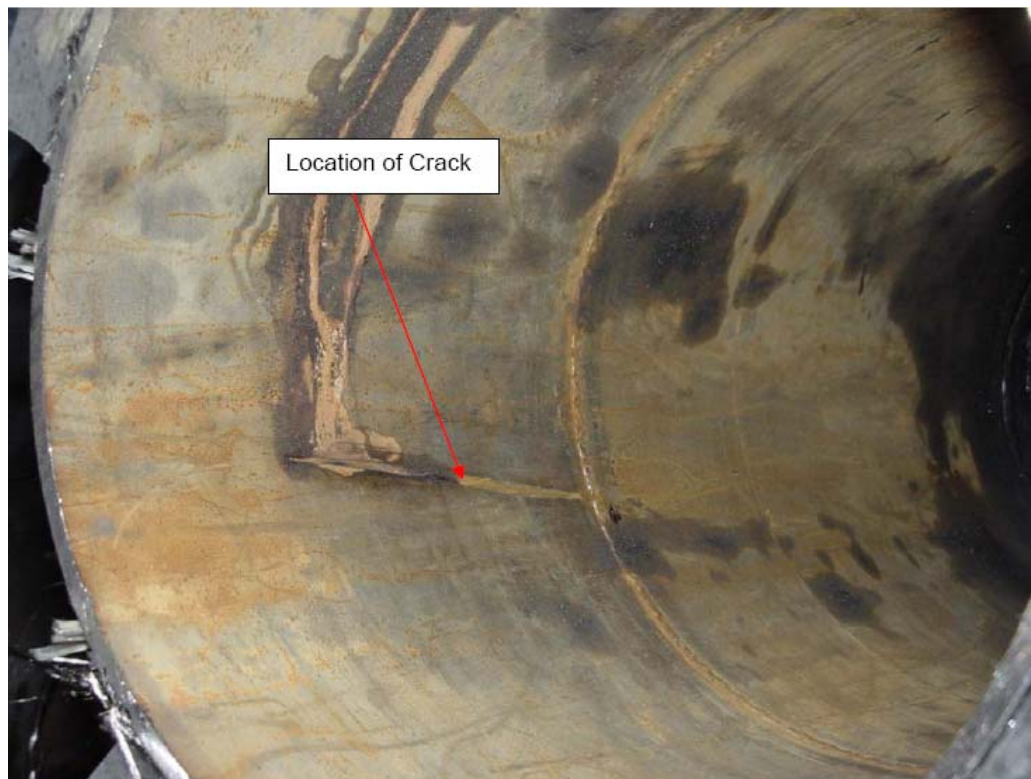


Fig. CPR 8 – Machined Crack in Steel Liner

Examination of the sample after stripping off the composite at the leaking end revealed that the leak path was immediately in-board of the rubber lip seal. The lip seal, a self-energizing concept, is formed by squeezing a sealant material into a thin groove cut axially in the MCI ramp (Fig. CPR 9 and 10). HNBR is then applied over the ramp and bonds to the sealant after curing.

In CLT-2, it was concluded that the bond between sealant and rubber was defective, with many visible voids (Fig. CPR 11). It should be noted that the leak did not go through the lip seal itself. Another observation was that the inside face of the rubber liner immediately above the liner crack bore an “imprint” of the crack. This was attributed to the jetting action of the water as the crack opened. The rubber was only indented, not penetrated.



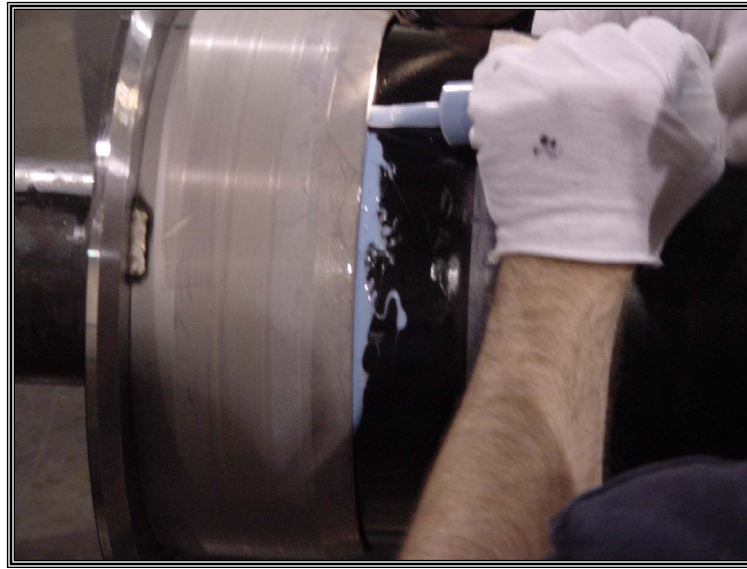


Fig. CPR 10 – Squeezing Sealant into Seal Groove

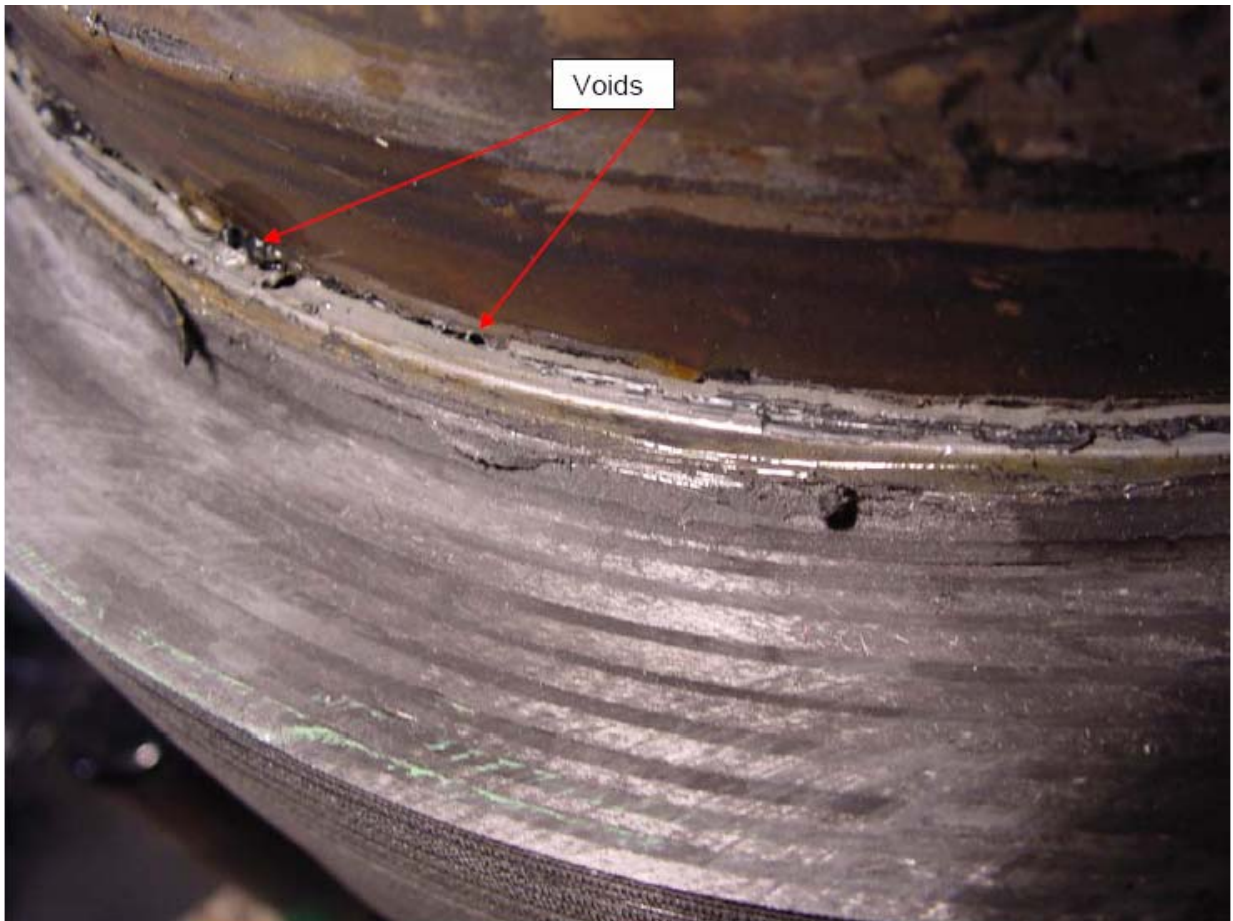


Fig. CPR 11 – Voids in Sealant/Rubber Interface Adjacent to Seal Groove

Following this investigation, it was decided to follow parallel paths to reach a solution. The first one was to improve the lip seal concept through variations in groove geometry, sealant type (silicone RTV rubber) and manufacturing process (curing of sealant and rubber over the MCI immediately after application, instead of after composite manufacturing). The other was to test a different concept, dubbed the “P” seal, proposed by DeepWater Composites. This consisted of a circumferential groove filled with a layer of HNBR, and an “O’ring”, as illustrated in Fig. CPR 12.

Both concepts were tried on mock assemblies by C4PO, both with inconclusive results. In order to maintain the schedule for delivery to Magnolia, a decision was made to produce two additional 20 ft long “cracked liner” test samples, one – CLT-3 – with the “P” seal, the other – CLT-4 – with the modified lip seal. Like CLT-2, each had a permeable liner in-between steel and rubber liners.

Both CLT-3 and 4 passed the FAT without problem. Unfortunately, when machining the crack on CLT-3, the groove was cut too deep, penetrating the steel liner, and the rubber liner outside was apparently damaged. On the next pressure cycle, the joint leaked. Because of the observed rubber damage, no conclusion could be drawn on the “P” seal effectiveness. The CLT-4 joint was pressured up in stages, with the last “hold” at 8,000 psi. It then leaked out at 9,300 psi. Both joints were depressurized without causing any bulging of the steel liner.

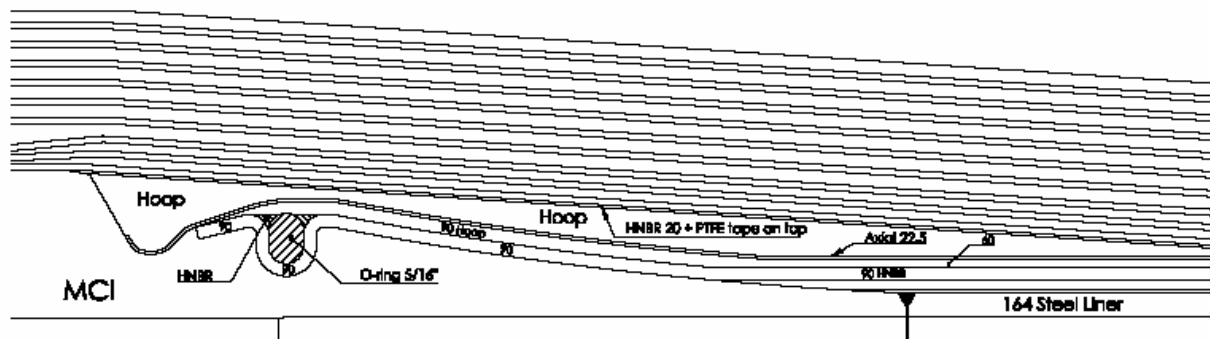


Fig. CPR 12 – “P” Seal

Attempts to patch the rubber liner to allow for further testing were unsuccessful on both joints.

Upon examination of the inner rubber liner of sample CLT-4, it was discovered that it had been cut right opposite the crack in the steel liner, corroborating the finding in CLT-2 above, except that the cut was much more severe and penetrated through the rubber, causing the leak. After reviewing the pressure data, it appeared that the steel liner cracked through only at a high pressure of approximately 9,200 psi. This high pressure caused a very severe water jet that cut through the rubber. This finding put into question the usefulness of the inner rubber liner as a backup seal to the steel liner. With this in mind,

DeepWater Composites contracted for a number of tests of various materials' susceptibility to water jetting action. The conclusion of this study was that the only practical solution to meet the project time frame was to "double hull" the tube with a second, thinner, steel liner. It should be noted that the high pressure failure on CLT-4 was actually fortuitous, as the water jetting failure mode would otherwise have been completely missed (it had not been identified by the risk analysis).

Although the decision to incorporate a secondary steel liner made the rubber seal issue less critical (with the secondary steel liner performing the dual roles of backup seal to the primary liner as well and water jet protection to the rubber liner), additional work was undertaken at C4PO to qualify the lip seal design. This was done in parallel to the manufacture of the main design verification test samples in order not to affect the schedule any further. These efforts included the manufacture of a short test mandrel, incorporating two lip seals and hoop fibers overwrap. These additional tests were ultimately unsuccessful.

Another rubber seal concept was also attempted, dubbed the "S" seal. This involved machining a square groove around the MCI ramp, then using sprayed Polyurea, instead of sheet HNBR, as the inner rubber layer. The Polyurea was sprayed all the way into the groove, then machined to a controlled groove width. The empty groove space was then filled with two split rings jammed against each other to exert the sealing force against the Polyurea (see Fig. CPR 13).

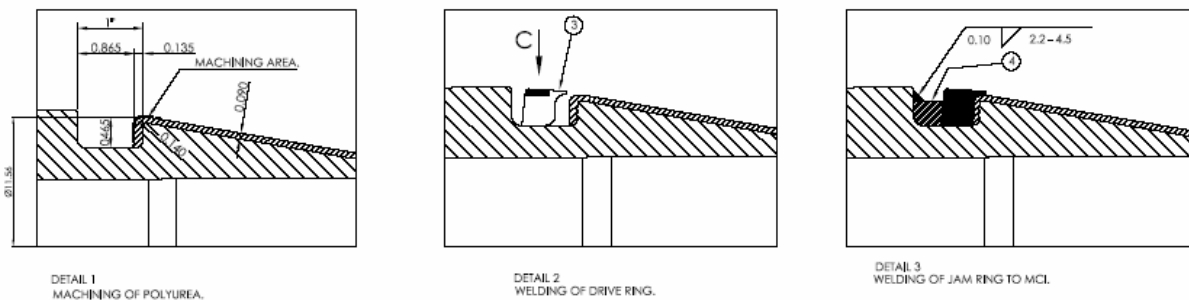


Fig. CPR 13 – “S” Seal Concept

This concept was first tested on short mock-up assemblies and showed enough promise to be incorporated on further test joints. However, it proved to be highly sensitive to any deformation of the seal groove (which would de-energize the seal) and produced mixed test results. It was eventually replaced by the Greene Tweed seal for the field joints (see Section 14).

7. Second Design Revision – Hoop Inserts and 4-trap MCI

Concurrently to the above activities on the cracked liner tests and rubber seal designs, DeepWater Composites developed their own in-house FEA model, in addition to the model

originally developed by Grover Engineering. The results of this work raised concerns on whether the axial capacity requirement (2500 kips) could be met with sufficient certainty using the existing design. Alternative composite and MCI layouts were modeled, with the ultimate recommendation to change to a 4-trap MCI configuration. Also, this work showed that a “hoop insert” on the load ramp of the MCI grooves (Fig. CPR 14) would be required, in addition to the fourth trap, to increase the laminar shear capacity across the traps. The hoop insert manufacturing feasibility was demonstrated on the CLT-3 test sample. These recommendations were adopted, and new (longer) MCI forgings were ordered.

The hoop insert comparative advantage was verified by fabricating two short test samples, with single trap MCI’s (referred to as the “Hoop Insert Verification” samples in the appendices). One sample incorporated the hoop insert, the other not. Axial fiber configurations were identical for both. The two configurations were simulated in the FEA model to predict the axial load capacities. Each sample was then subjected to axial load tests, including “hold” periods to evaluate static fatigue (creep), then pulled to failure, with the following results:

	<u>FEA Prediction</u>	<u>Test (failure)</u>
No hoop inserts	> 325 kips	498 kips
With hoop inserts	> 550 kips	704 kips

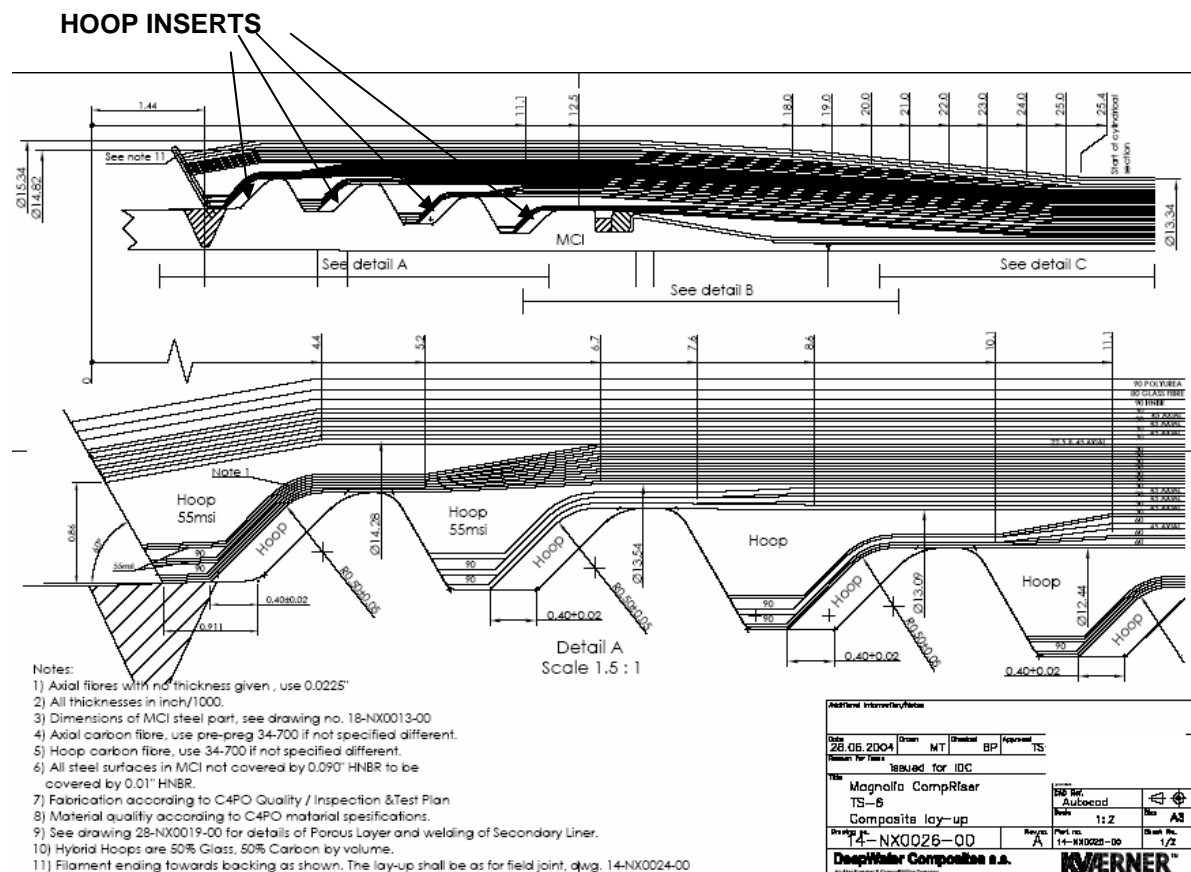
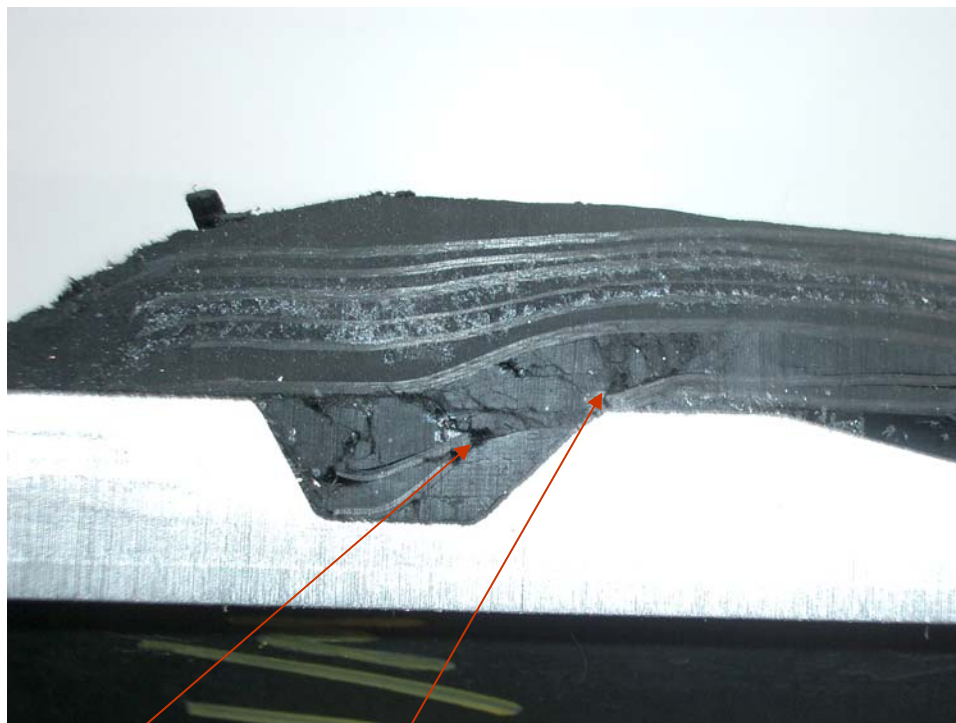


Fig. CPR 14 – 4-Trap MCI with Hoop Inserts



Fig. CPR 15 – Hoop Insert



This end was attached to that end at the completion of fabrication.

Fig. CPR 16 – Cut-out of Single Trap Hoop Insert after Axial Failure Test

8. Verification Testing – Phase 1 (TS-1, TS2, TS-3)

Prior to the design verification phase, a “global analysis” of a hybrid riser (steel riser with ten composite joints) was performed by ABB-Lummus, the Magnolia design contractor. This was essentially a revision of the steel riser analysis, but accounting for the properties (mainly lighter weight) of the ten composite joints inserted at the 1000 and 3000 ft water depth level. From this analysis, maximum expected composite joint loading conditions were derived. These results were in turn used to finalize the design basis for the composite joints.

The Basis of Design was produced by ConocoPhillips and establishes the overall design factors and verification test results to be met to satisfy the Magnolia requirements. The safety factors of the composite production riser (CPR) joints involve consideration of three factors: 1) the strength-time dependence of the composite structure, 2) the required high reliability of the CPR due to the novelty of application and the lack of plastic deformation, and 3) the acceptable safety factors for steel components. Starting from the maximum loading conditions established by the global analysis, the Basis of Design derives all the safety factors and establishes the minimum design verification tests summarized in the table below. Note that the safety factors used to obtain the required test values account for the fact that the design is based on the FEA, and verified through single tests, as opposed to a large number of tests. Long term fatigue performance evaluation makes use of the data collected by the NIST Project.

Qualification Testing Plan

Test	Criterion	Failure mode
Burst Test, psi	$\geq 21,350$	Tube body
Tensile Strength, kips	$\geq 2,420$	MCI
Axial Fatigue at mean of 700 kips and range of 200 kips	100,000 cycles	No failure
Collapse, psi	2,500	No failure
Impact	10 kJ followed by 10,000 psi pressure	No failure
Cracked internal liner	Identify acceptable depressurization rate	No liner collapse

The first three 10 ft long, full diameter test samples were manufactured by C4PO using metal assemblies welded at SMI/PK. The samples were configured as per the second design revision above, i.e., with hoop inserts and four traps. They included the permeable layer between steel and rubber liners, but the secondary steel liner was not yet incorporated. The latter concept was still being developed at the time.

All three samples were taken through the FAT procedure. They were fitted with an array of strain gauges to establish a reference record during autofretage, pressure test and burst tests. The burst sample (TS-2) was also equipped with the various in-service performance monitoring system under evaluation (refer to Section 11). FAT's were performed either at

C4PO or at Stress Engineering. All design verification tests were performed by Stress Engineering in Houston.

TS-1 was used for the ultimate axial test. The test program called for loading the sample to 2400 kips, hold it for 100 hours, then increasing to failure. Pulling head adapters were welded to each end box fitting. The sample was taken to a 2400 kips load and held there. After 18 minutes, the weld between one of the pulling heads and the joint box fitting failed. The failure was very sudden (brittle), resulting in a very high shock load level to the test joint. Remarkably, this joint was retested and survived up to 2358 kips axial load, before laminar shear failure at the top of the traps (the failure mode predicted by the FEA). Also, fatigue calculations showed that the 2400 kips load held for 18 minutes is equivalent to an initial load capacity in excess of 2420 kips.

TS-2 was selected for the burst test. The joint burst at 20,983 psi in the tube section (Fig. CPR 17), with the steel liner rupture occurring away from any weld.. Although close to the design requirement, this pressure fell substantially short of the FEA prediction.



Fig. CPR 17 - TS-2 Test Sample – Before and After Burst Test

The TS-2 test result prompted an in-depth review of the FEA. It did not reveal any specific flaw with the analysis itself. However, a visual inspection of the test joint composite cross section showed that, due to the manufacturing process combining pre-impregnated axial strips and filament wound hoop fibers, hoop layers exhibited some variations in thickness (“waviness” – Fig. CPR 18), whereas the model assumed a more regular geometry, as had been achieved on the NIST and Heidrun projects, where helical filament wound fibers had been used instead of axial mats. Further analysis determined that the effect of this waviness on the stress distribution was not negligible. This mostly explained the discrepancy between FEA and test. FEA allowable stresses input parameters were subsequently reduced to reflect this situation, resulting in the requirement for additional fibers.

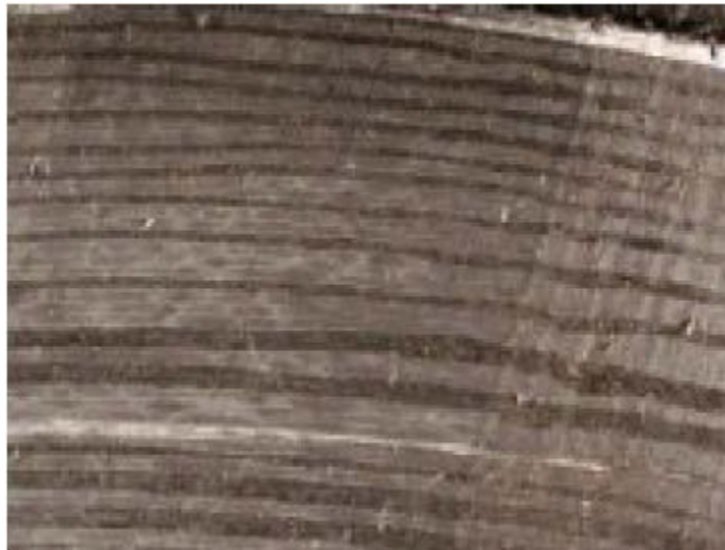


Fig. CPR 18 – Hoop Layers (dark) “Waviness”

Sample TS-3 was subjected to the impact and collapse tests. Both MCI and tube section were impacted with 5 and 10 kJ energies. There was no damage observed at the 5 kJ level. However, inward denting of the inner steel liner was observed after the 10 kJ impact on the tube section. The sample was then pressure tested to 10,000 psi, and held. The internal pressure also had the effect of pushing the inner dent back out and the full circular bore had been regained.

Next, TS-3 successfully passed a 2500 psi collapse test, with the outer rubber liner still intact. As a last step, the outer rubber was cut to allow water ingress and pressure to be applied on the inner rubber and steel liners. This caused collapse to occur after 8 minutes at 2000 psi in the already weakened area that had been damaged by the 10 kJ impact.

9. Third Design Revision (TS-4)

Following the first series of tests, the composite design was again revised with additional hoop and glass fibers for increased burst capacity. Furthermore, additional impact protection materials were investigated by C4PO.

Another short test joint, TS-4, was then fabricated based on the revised design. It also included the secondary steel liner and “S” seal. The secondary liner consists of 0.049” thick steel sheets (approx 30 ksi yield) formed and welded around the primary liner and dry fiber permeable layer, in 8 ft sections. At each end, this liner is also welded to the MCI in order to complete the seal. See Fig. CPR 19.



Fig. CPR 19 – Secondary Liner Fabrication

Finally, TS-4 was fitted with an additional impact protection outer layer consisting of a foam filled honeycomb wrap. The sample was impacted to 10 kJ on the tube section, without damage to the inner steel liner. After this impact, the sample was subjected to a 2500 psi/4 hour collapse test.

TS-4 was then taken to a burst test, and failed at 18,404 psi, again less than predicted. The failure occurred away from any primary liner weld and away from the impacted zone. However, the failure line was alongside the secondary liner longitudinal weld overlap. Fig. CPR 20 shows a section of the tube away from the failure area.

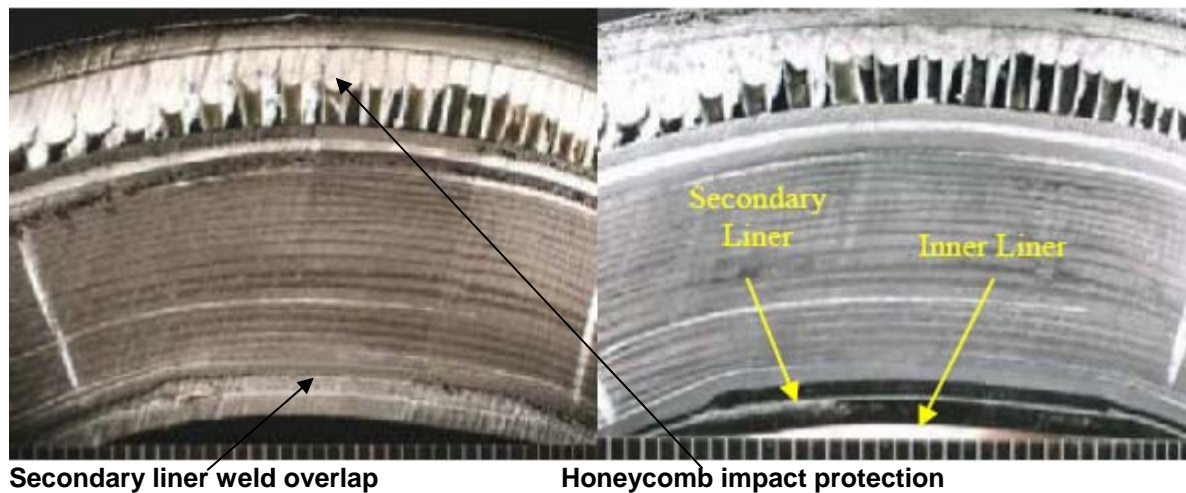


Fig. CPR 20 – TS-4 Section after Burst Test

The extra thickness of the weld overlap causes localized stress concentrations in the composite hoop layers immediately around its edges. An FEA model of this effect explained the failure at the lower pressure. As a result, an alternative secondary liner welding procedure, using longitudinal and girth backing strips, was developed to eliminate the need for an overlap. The permeable layer is installed first, then cut to allow placement of the backing strips. The circular strips are also undercut to allow for fluid passage from one 8 ft section to the next, and ensure continuity of the permeable layer. The secondary liner sections are then clamped around and welded together along the backing strips.

The TS-4 test also prompted a closer examination of the impact of metal assembly ovality on stress distributions in the inner composite hoop layers. FEA work determined that ovality will significantly affect burst capacity, and that the ovality measured around the inner Polyurea coating should not exceed 0.73%.

Note: Ovality = (Max. Diameter – Min. Diameter)/Nom. Diameter.

10. Verification Testing – Phase 2 (TS-5A , TS-6)

A final two 10 ft long design verification test samples were fabricated, both incorporating the revised secondary steel liner fabrication method, in order to complete the required testing.

TS-5A (labeled “A” due to a manufacturing problem with the initial metal assembly) was dedicated to impact and burst testing. The foam-filled honeycomb protective layer used on TS-4, while successful, proved difficult from a manufacturing standpoint, particularly when trying to pack all the voids with the foam. Alternatives were sought, and syntactic foam offered the most expedient solution. The foam comes preformed in half shelves ready

to be clamped around the joint. After the foam is secured in place, a final Polyurea layer is sprayed on the joint. This approach was employed on TS-5A.

TS-5A was first impacted at 10 kJ (Fig. CPR 21). Visual examination, including cutting out the section of syntactic foam around the impact area, did not detect any damage. The joint was then burst tested, with ultimate failure occurring at 25,716 psi, satisfying the burst requirement. The DeepWater Composites FEA model had predicted a burst capacity of over 23,644 psi. An independent FEA performed by Grover Engineering Mechanics had corroborated this prediction prior to the test. Again, it should be noted that the failure occurred away from the impacted zone, and away from any inner liner weld. The burst sequence was first rupture of the hoop layers around the tube section, followed by ductile failure of the steel liner.



Fig. CPR 21 – TS-5A Impact Test

The last required verification test was cyclic axial fatigue, for which TS-6 was built. The test performed by Stress Engineering consisted of 102,978 cycles between 600 and 800 kips axial loads, at a frequency of 0.28 Hz (a 3.6 second cycle, over 4 days total duration). The sample had been instrumented with 2 displacement transducers and 24 strain gauges, located both on the OD and ID (steel liner, near the MCI/liner girth welds) of the joint.

Strain and elongation readings were consistent throughout the test. There were no detectable changes in the strain responses of the sample during the test period, other than normal gauge drifts.

This test met the fatigue testing requirement. The TS-6 sample is intact and could be used for additional tests.



Fig. CPR 22 – TS-6 in Cyclic Load Frame

Following TS-1 (axial), TS-5A (burst) and TS-6 (fatigue), the composite structural design had met all the basis of design requirements.

11. Performance Monitoring

Because of the multilayered structure of composite riser joints it is impractical to inspect them after completing the fabrication. Therefore, the structural integrity must be ensured by addressing it during design, material purchase, manufacturing, and factory acceptance pressure tests. However, situations may still arise that would require an assessment of the composite joint integrity while in-service. This can be achieved by monitoring changes in the laminate stiffness which can be assessed by measuring changes in the internal strains under known loads or by changes in the natural frequency of the joint.

Several potential integrity monitoring systems were evaluated. These systems included fiber optics, vibration monitoring and magnetic permeability steel sensors. They were installed on some of the test joints, and their respective response to pressure cycles was compared to the data collected from standard strain gauges. On one occasion, all of the different types of sensors were fitted to one single test joint (TS-2 burst test).

As part of the effort to address the robustness issue of the **fiber optic sensors**, new designs were fabricated by two companies, Smart Fibers and Insensys. Both companies supplied the sensors in the form of patches, with each patch including multiple sensors to measure hoop and axial strains. The purpose of supplying the sensors in a patch form is to improve sensor survivability. Once they are installed, the repair of embedded sensors is impossible. Sensor survivability is an important issue, which can be broken down into two areas; the embedded sensors and fiber exit points.

In spite of the attempts by the two suppliers to design and provide a robust fiber optic sensor assembly, several sensors failed. This makes the use of the fiber optic sensors



questionable without additional developments and excessive redundancy. In addition, a concern was raised regarding the penetration of the fiber optic cable through the composite and the risk of water leaking into the composite around the penetration (Fig CPR 23). Both of these issues contributed to the decision to eliminate the fiber optic sensors as an option for the Magnolia CPRs.

Fig. CPR 23 – Optic Cables Exiting Composite

Since changes in stiffness can be assessed by changes in the natural frequency, **accelerometers** were fitted to TS-2 by Fugro Structural Monitoring. An automated hammer tool continuously impacted the sample during the burst test as a vibration source. The results did not show any significant trend in the frequency response spectra. It was suggested that this may have been attributed to the speed by which damage was introduced during the test and if the damage occurred at slower rate, a trend may be developed. Since the results were not very encouraging, the decision was made not to evaluate this concept further.

The concept of the **magnetic permeability sensors** (Fig. CPR 24) is based on the correlation between the changes in the magnetic permeability of magnetic materials such as ferritic steels and the electromagnetic field close to the surface affected by the stress level in the material.

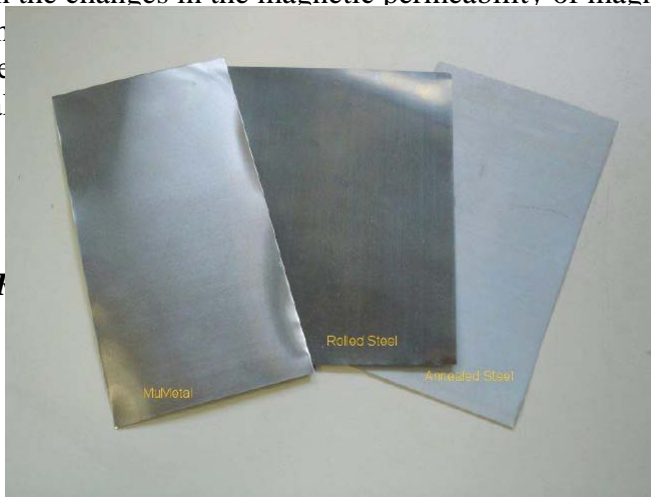


Fig. CPR 24 – Magnetic Permeability Sensors

(StressProbe)

Two types of sensors were evaluated. The first type was developed by TSC Inspection Systems and is marketed under the name StressProbe (Fig CPR 24). The sensor of this system continuously measure changes in the strain. This system is considered active because at any time the sensor is interrogated, it gives the instantaneous strain at that time.

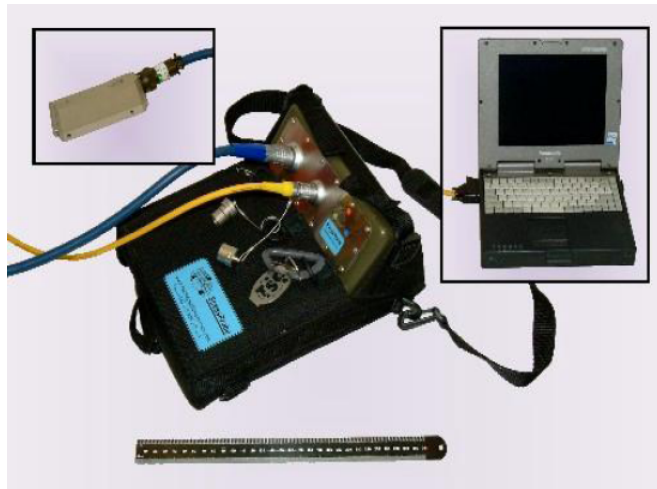


Fig. CPR 25 – StressProbe Instrumentation

The second type was developed by StructureMetrix Inc in a project funded by ChevronTexaco. The TRIP metal sensor (Fig. CPR 26) undergoes a permanent change in its magnetic properties as a function of the maximum stress. This sensor monitors only the maximum strain and, therefore, is considered as a passive system because at any time the sensor is interrogated, it only gives the maximum strain it was subjected to during its service life. This “memory” sensor usefully complements the active TSC sensors.



Fig. CPR 26 – TRIP Metal Sensor Taped on Test Joint

There are two main advantages that the magnetic permeability sensors offer over the fiber optic sensors. The first is that the sensors are made of metal foil and thus are more robust. The second is that the sensors can be interrogated by generating an external magnetic field, without the need of having any penetration or contact between the probe and the sensor. This makes them more suitable for an underwater application. Both TSC and StructureMetrix sensors have shown to be reliable in monitoring the strains in the composite laminates. Therefore, it was determined that the field joints would be instrumented with these sensors.

The feasibility of developing a subsea monitoring system tied to the Magnolia acoustic current monitoring equipment was investigated. However, such a system would have been costly and could not practically be deployed in time for the Magnolia installation. At the time of this report, neither company has developed an ROV deployed probe to interrogate the sensors either. It is hoped that such a probe will be developed within the next three years.

The results have shown that the magnetic permeability steel sensors offer the best approach for monitoring the integrity of the production riser joints. While the sensors are available, actual in-service monitoring will require an additional effort to develop an ROV deployed monitoring probe to interrogate the sensors.

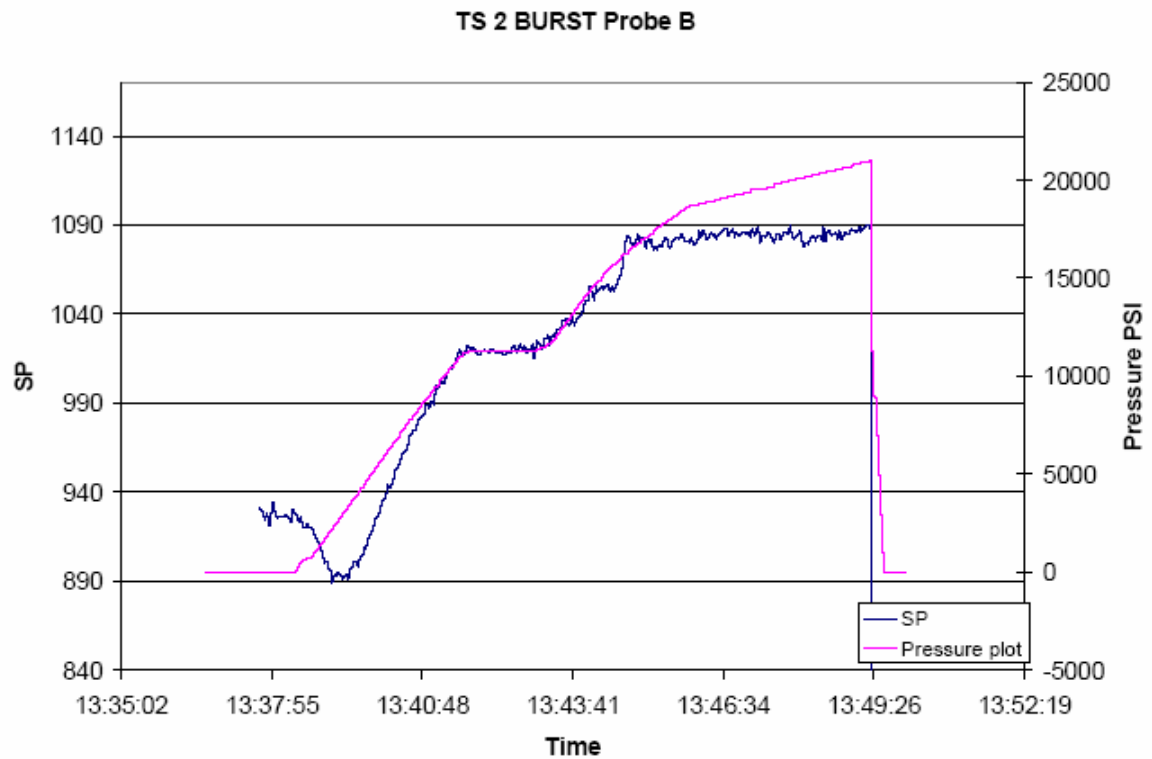


Fig. CPR 27 – StressProbe Response (TS-2 Burst Test)

12. Cracked Liner Testing (CLT-5, 6 & 7)

Due to the aforementioned problems with the secondary seal, the previous cracked liner tests were unsuccessful in verifying the depressurizing rate capacity of the composite joint in the presence of a longitudinal crack in the inner steel liner. A new specimen, CLT-5, was therefore manufactured, this time incorporating the secondary steel liner as secondary seal. The sample was subjected to the two FAT pressure cycles. Followed by quick (not controlled) depressurizations. After removing the test caps, it was discovered that a longitudinal crack was already present in the inner steel liner. This was caused by the failure of a weld repair of a previously machined crack. Since the post-FAT depressurization had not been controlled, it resulted in buckling of the inner liner (Fig. CPR 28). While this test showed that the secondary steel liner was capable of withstanding the FAT pressure, thereby validating the secondary seal, the requirement to determine a safe depressurization rate was still outstanding.

A CLT-6 test joint was then manufactured by C4PO in Sacramento, with secondary steel liner (but no tertiary rubber seal). The secondary steel liner material for this sample was pro- cured locally (i.e., different from that used by PK in Houston for the field joints and

other test samples). This joint leaked at 10,500 psi during FAT, and the test was aborted. Subsequent examination revealed a crack on the liner side of the primary liner to MCI girth weld, and a small hole (inclusion defect – see Fig. CPR 29) through the secondary liner.



Fig. CPR 28 – Bulge in CLT-5 Inner Steel Liner



Fig. CPR 29 – Hole through Secondary Liner – CLT-6

As there was no longer any spare liner material to manufacture another 20 ft long sample for cracked liner testing, it was decided to use one of the already delivered full length field joint metal assemblies (fabricated by PK in Houston) for a CLT-7. A successful cracked liner test was achieved with this joint. After manufacturing the crack in the primary liner, the joint was repeatedly pressured up to 10,000 psi, followed by depressurization at controlled rates of 250, 500, 1,000 and 2,000 psi/min respectively. No primary liner buckling was observed, indicating that the permeable layer between the two steel liners does indeed achieve its purpose of allowing for reasonable riser pressure bleed-off rates.

After the cracked liner test, a penetration was also machined through the secondary steel liner in order to test the “S” rubber seal (redundant tertiary seal). The joint was pressured up again to 10,000 psi, but the rubber failed to hold, leaking through the composite in the vicinity of the manufactured cracks. Additional pressure tests indicated the rubber seal would still hold over 3,000 psi without leaking.

The composite around the leaking end of CLT-7 was stripped off for examination. Surprisingly, two full penetration cracks were also found in the secondary liner to MCI weld (Fig. CPR 30). It is not clear whether these cracks opened during the testing or only after releasing the stress from the surrounding composite. Judging by the fact the joint did not leak until after the secondary liner was penetrated, it seems these cracks were still closed at least until that time.



Fig. CPR 30 – Secondary Liner Cracks in CLT-7

13. Full Length Metal Assemblies Fabrication and Inspection Issues

By the time the CLT-7 test was being performed, eight (including CLT-7) full length “field joint” metal assemblies had been manufactured by PK and delivered to C4PO. As the results from CLT-6 and CLT-7 raised concerns about the integrity of the various liners and girth welds, it was decided that additional inspection work was warranted before proceeding with field joints manufacturing.

The metal assembly fabrication sequence consists of (refer to Fig. CPR 31):

- 1) Machining of DrilQuip connectors and MCI’s from A707 forgings.
- 2) Welding of each end assembly consisting of box or pin, 11 ¾” pipe spoolpiece, and MCI (all 1” thick welds performed by DrilQuip).
- 3) Application of Thermally Sprayed Aluminium on end assemblies (to protect metal not

covered by composite).

- 4) Fabrication of 0.165" WT primary liner by welding two sections to the required 53 ft length (primary liner pipe had been delivered in 40 ft long sections).
- 5) Welding of primary liner to each end assembly MCI (another two 0.165" girth welds).
- 6) NDE of girth welds (X-ray).
- 7) Pressure test assembly to 2300 psi (to stay below primary liner yield).
- 8) Apply dry fiber permeable layer, and cut sections (both longitudinal and circumferential) to accommodate secondary liner backing strips.
- 9) Form secondary steel liner (comes in 8 ft long, 0.049" thick sheets) around primary liner and permeable layer, and weld longitudinally and circumferentially.
- 10) Weld secondary liner ends to MCI's to complete pressure seal.
- 11) NDE of secondary liner welds (dye penetrant).
- 12) Machine port through secondary liner at each end for Helium test. Helium check all welds. Plug ports.

The issue was now to check the inner liner girth welds from the inside of the joint, as well as detect defects in the thin secondary liner base metal (for small defects as seen on CLT-6) and end welds, with outside access only.

The first step was to assemble a remotely operated camera carrier, with a camera swivel for close visual examination of the girth welds inside the pipe. Such a crawler was conceived and built by C4PO. It was successful in obtaining a close picture of the inner liner welds, but, since these welds could not be ground, their very rough aspect made it difficult to detect any crack. It was sufficient, however, to prompt the search for another inspection method.

For the secondary liner, a test sample was built by C4PO in order to evaluate how accurate NDE methods would be in detecting defects in such a thin metal. A secondary liner base metal plate was machined with various very small, non penetrating, holes and cracks on one side, with locations carefully recorded, then rolled into a short pipe section. Standard X-ray techniques were unable to detect the defects. The sample plate was then shipped to Matrix Inspection and Engineering in Houston, who used their ACFM (Alternating Current Field Monitoring) device, and were able to locate most of the defects, but not all.

The ACFM equipment was mobilized to Sacramento to inspect the secondary liners. The base metal was scanned on two joints and recorded a number of indications, but their nature was uncertain, and none appeared to be a surface breaking flaw. Secondary liner to MCI welds were scanned on all joints, with 18 indications recorded (diagnosed as weld undercuts). A secondary liner weld repair procedure was subsequently developed and used to repair all welds with significant indications. As for the base metal, it was decided to perform an Acetone test on each secondary liner after sandblasting. However, visual inspection after sandblasting was sufficient to detect small holes, apparently uncovered by the blasting action.

The ACFM was then tried on the inner liner girth weld of cutout sections from CLT-7 and other test pieces. It proved to be quite accurate in detecting weld defects, including dimensions. The remote camera carrier was therefore modified to enable inspection of the inner liner girth welds with the ACFM probe (Fig. CPR 32). In the seven remaining metal assemblies, a total of thirteen indications were detected. Twelve were shallow, and, after some grinding, were determined to be caused by the heat affected zone from the secondary liner to MCI weld. The most pronounced indication was 13 mm long x 1.3 mm deep and could not be ruled out. That metal assembly was rejected.

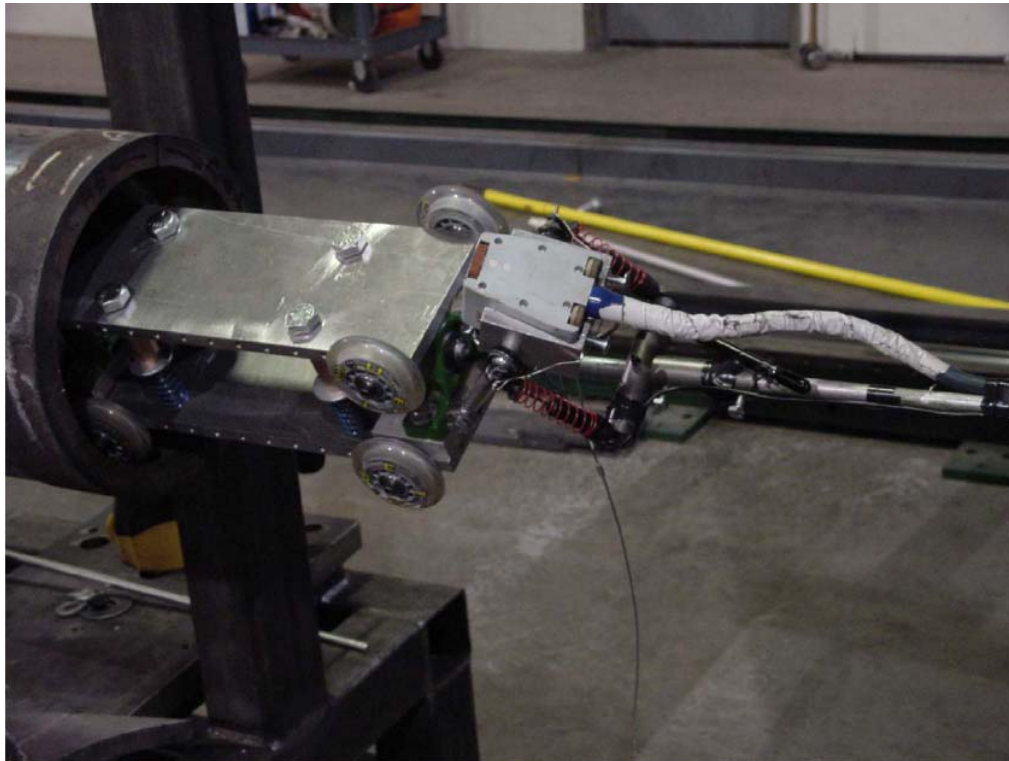


Fig. CPR 32 – C4PO Camera Crawler with ACFM Probe

14. Alternative Rubber Seal Test (CLT-8)

Following the metal assemblies' inspection, one last full length test joint was manufactured, to fine tune the composite fabrication process and try an alternative rubber seal design developed by Greene Tweed & Co in Houston. The Greene Tweed concept (Fig. CPR 33) differs from the "S" seal in that it compresses the rubber seal radially instead of longitudinally. It uses the same groove profile and the same machining of the Polyura into the groove, but uses a separate rubber ring to effect the seal. This ring is compressed by a split Arlon ring, with a gap between the two lips such that, when fully closed, it achieves the required compression level for a 10,000 psi seal. The Arlon ring is closed by tightening a steel band, which is in turn kept in compression by filament wound Zylon shrunk with UV.

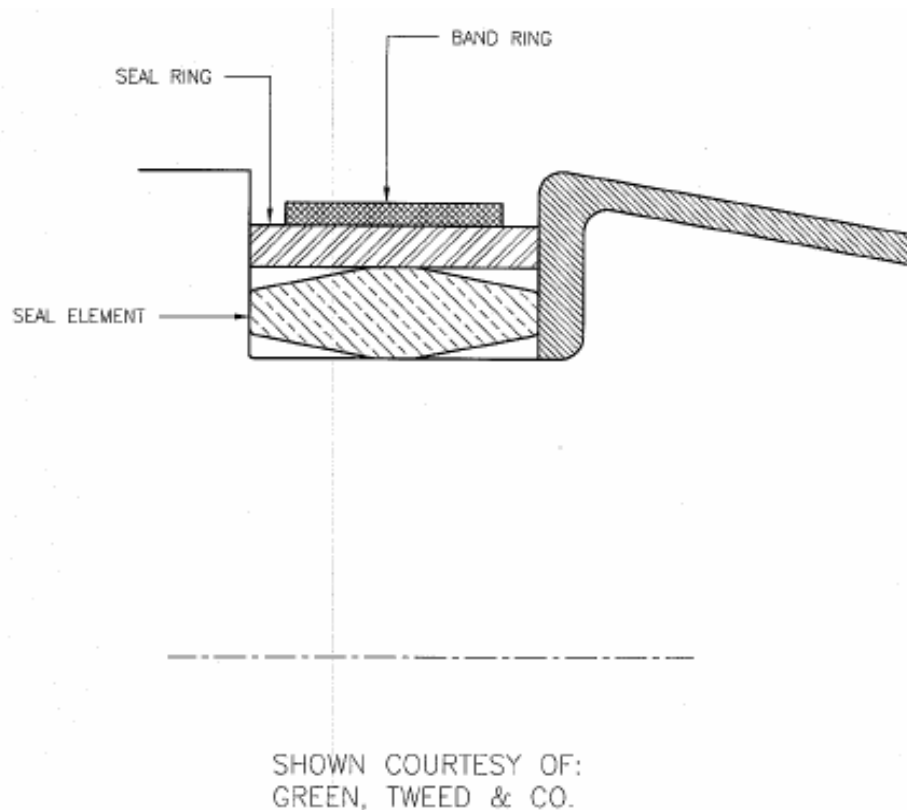


Fig. CPR 33 – Greene Tweed Seal Assembly

After FAT, a crack was machined through the primary liner, and the secondary steel liner was subjected to a 10,000 psi/60 min test. The crack was ground open, and the secondary

liner also ground through until the Polyurea was uncovered. The rubber seal was then successfully tested to **11,250 psi**.

15. Field Joints Manufacturing

Following the successful CLT-8 test, a total of five field joints were manufactured during November and December 2004. Figures CPR 34-36 illustrate the finalized design of the field joints.

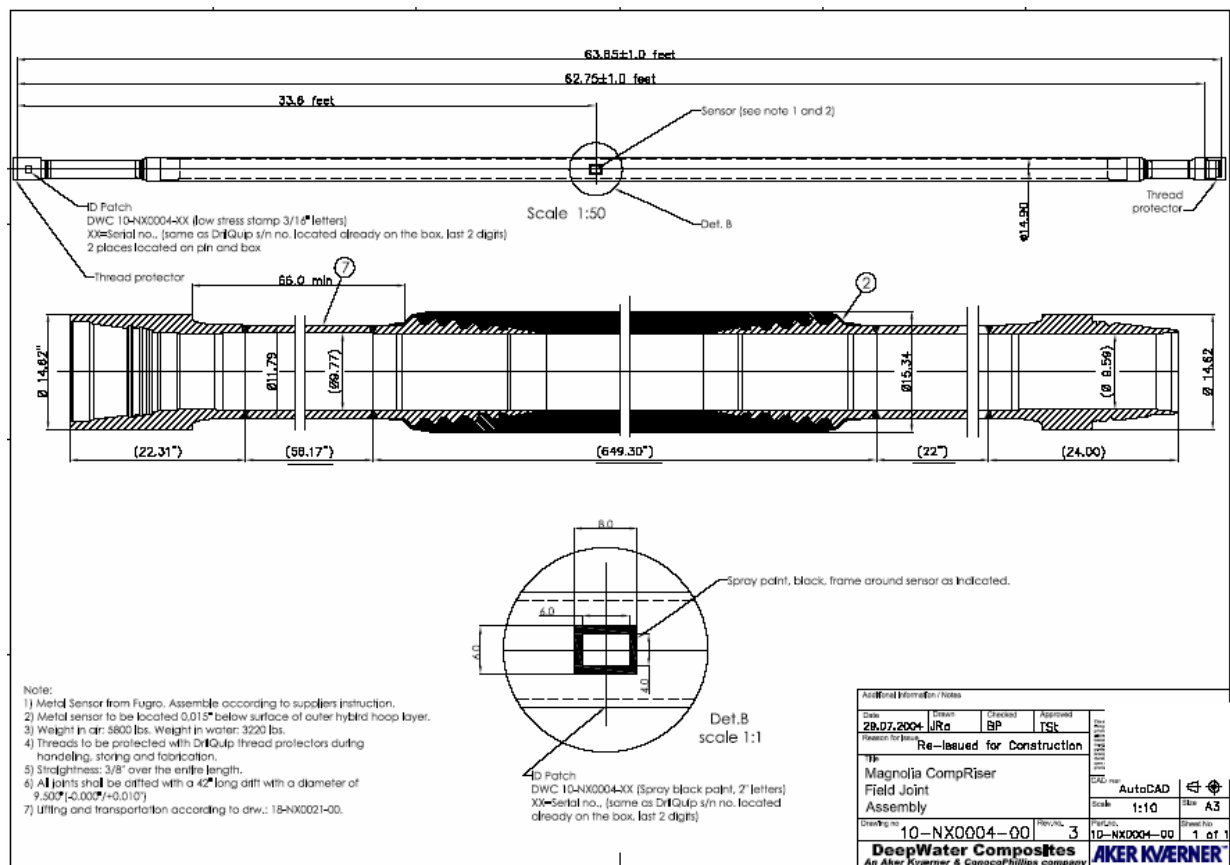


Fig. CPR 34 – Composite Field Joint Assembly

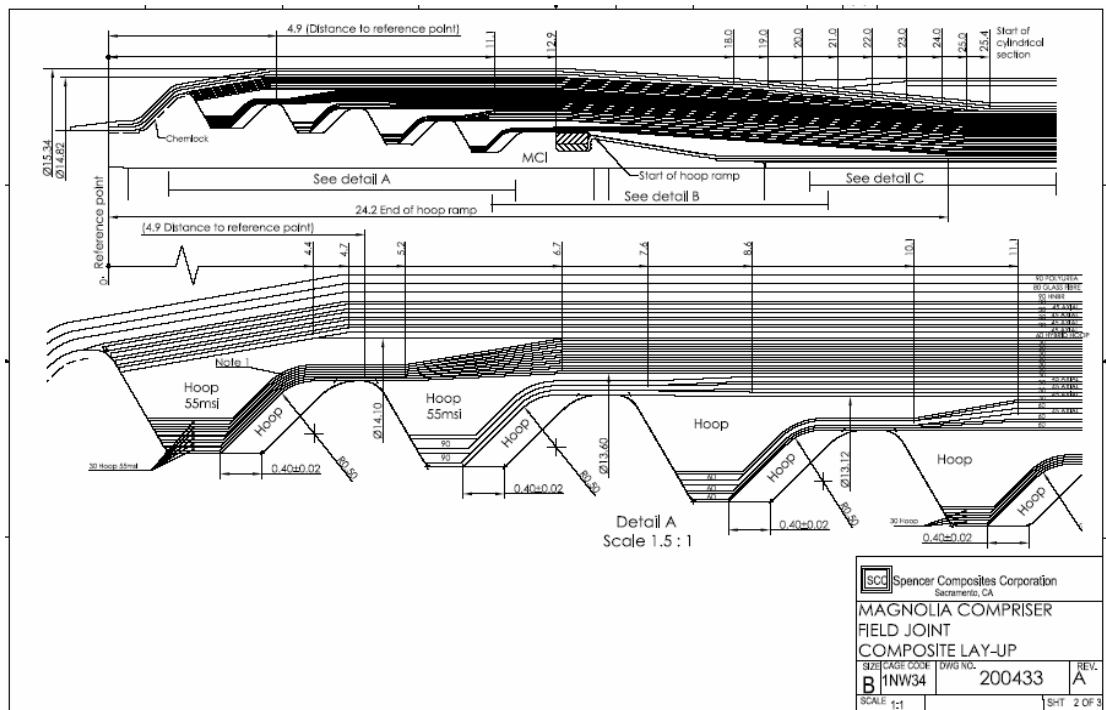


Fig CPR 35 – Field Joint Composite Lay-up Details (1)

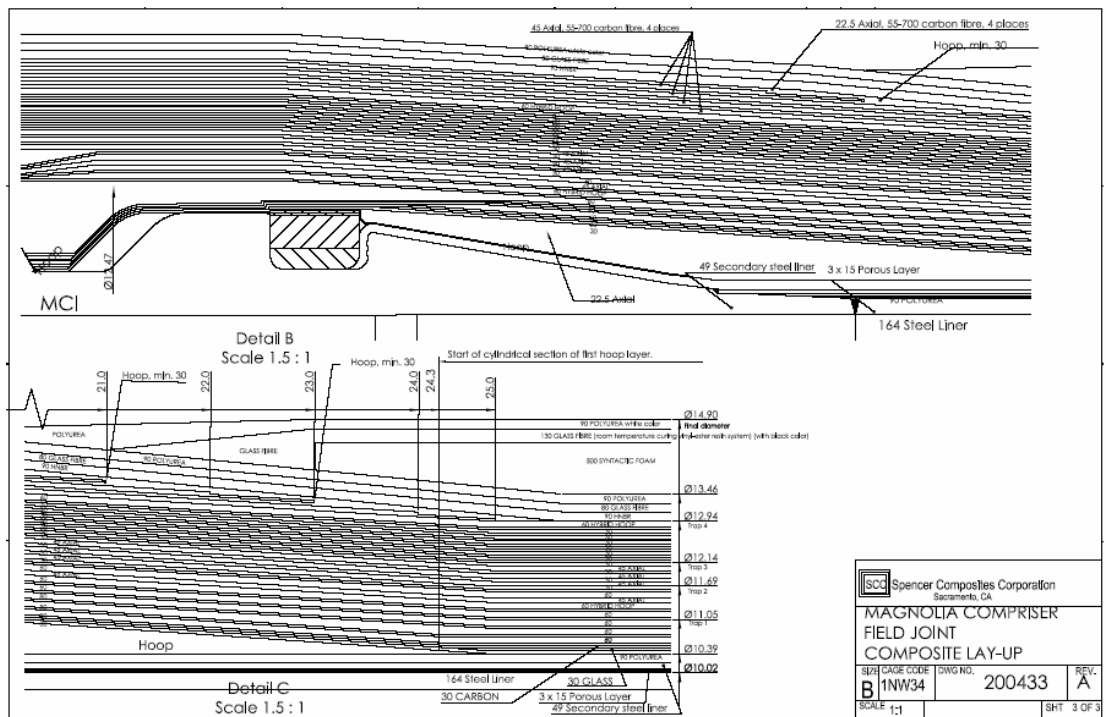


Fig CPR 36 – Field Joint Composite Lay-up Details (2)

Following is a description of the main composite manufacturing steps used at C4PO for the Magnolia field joints.

1) Metal Assembly Geometry Check

Each metal assembly is checked for ovality and straightness. Excessive ovality will adversely impact burst capacity (ref. Section 9 above). Although some of the metal assembly ovality can be “smoothed out” by the Polyurea layer, the 0.73% limit may not be achievable if the metal assembly is too far out of round.

Assembly straightness is an important issue for composite filament winding. As the 63 ft long joint is being rotated during filament winding, out of straightness will cause wobbling, which in turn affects the layout quality of the hoop fibers. This was illustrated during the manufacturing of the CLT-7 sample. The wobbling can be somewhat controlled by the application of a counter bending moment at each end while rotating the joint (see below), but there are limits on tolerable metal assembly out of straightness, particularly if two or more significant inflection points are present. One of the metal assemblies was rejected because of this.



Fig. CPR 37 – Metal Assembly and Support Cradle Lifted out of Shipping Box

2) Installing Metal assembly in Winding Cart

After geometry check, winding extensions are made up to each end. The purpose of these extensions is to allow rotation of the joint without inserting anything in the DrilQuip pin and box. They also provide reaction points to apply the counter bending moment in the winding carts. The joint is then lifted into the winding cart. Joint weight is being supported on rollers, with a second set of adjustable roller available to apply a downward force on the extensions for counter moment.



Fig. CPR 38 – Winding Extension Makeup (left)/Joint in Winding Cart (right)

3) Sandblasting and Polyurea Application

The liner section is sandblasted, then examined for any hole or punch mark in the secondary liner. Most can be detected visually, although an Acetone test is also performed. After repairing any defect, the inner Polyurea layer is sprayed on, from seal groove to seal groove. Each groove is partially filled to allow for machining of Polyurea (see below).



Fig. CPR 39 – Acetone Test (left)/Pin hole in Secondary Liner (right)



Fig. CPR 40 – Polyurea Application (left)/Seal Groove partially Filled with Polyurea (right)

4) Rubber Seal Installation

The Polyurea in the seal groove is machined to fit the seal ring width. The rubber seal ring is then stripped over the end connections and MCI, and into the groove. The Arlon ring is snapped into place around it, then closed with a steel band to achieve the right level of seal compression/energization. As the steel band is too thin to keep the ring in compression with 10,000 psi applied under the rubber, a layer of high strength Zylon is filament wound around it and shrunk with UV light.



Fig. CPR 41 – Polyurea Machined in Seal Groove (left)/Rubber Seal Ring in Place (right)



Fig. CPR 42 – Split Arlon Ring (left)/Tightening Steel Band to Close Arlon Ring Gap (right)



Fig. CPR 43 – Steel Band Tacked in Place (left)/Application of Zylon Fiber (right)

5) Filament Winding and Axial Mats Application

Hoop fiber is first wound around the MCI ramp, covering the seal area, in order to achieve the desired slope profile. A HNBR layer is applied in the MCI traps. A hoop insert is then wound in each trap. The first layers of composite are then applied in alternating axial and hoop, until the first trap is filled. The axial fibers are in the form of strips pre-impregnated with resin. The hoop fibers are wound individually, going through a resin bath. Some of the hoop layer are fiberglass.

The joint is rotated without intermediate support and without any inner mandrel. To combat deflection of the thin liner section, vertical force is applied at each winding extension as necessary to control wobbling. However, this causes fatigue stress in the vulnerable MCI/liner welds. Once the first trap is complete, the joint is therefore placed in

the oven for a “B Stage” cure, i.e., a partial curing cycle of the composite matrix. Its purpose is to stiffen the joint and minimize liner weld fatigue during the remaining filament winding.

After the B stage cure, the remaining composite is applied until all four traps have been filled. Metal sensors are inserted before the last hoop layer. The next layer is HNBR, extending to the end of the MCI’s, for external water seal. Finally, a helical glass layer is applied for protection. The joint then goes back in the oven for final curing of composite and HNBR at 350 deg F.

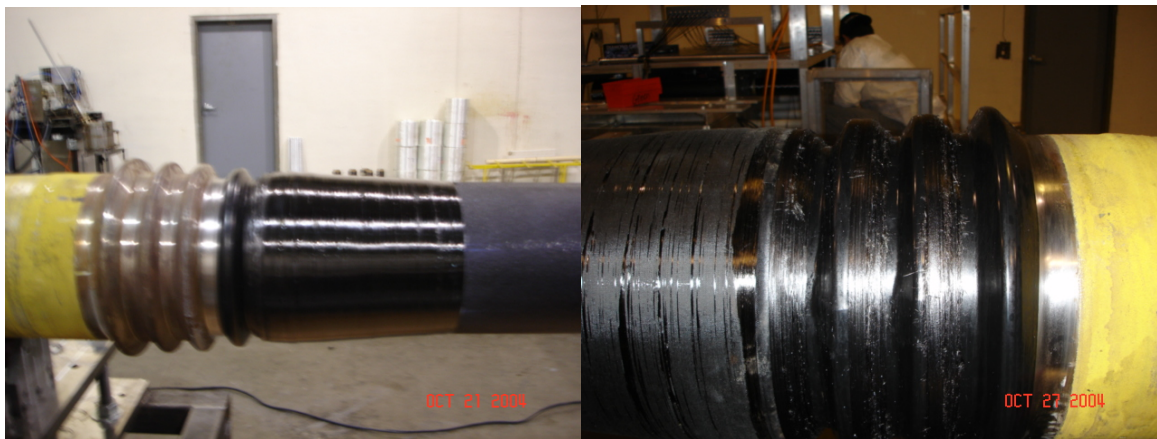


Fig. CPR 44 – Hoop Ramp over Seal Area and Hoop Inserts

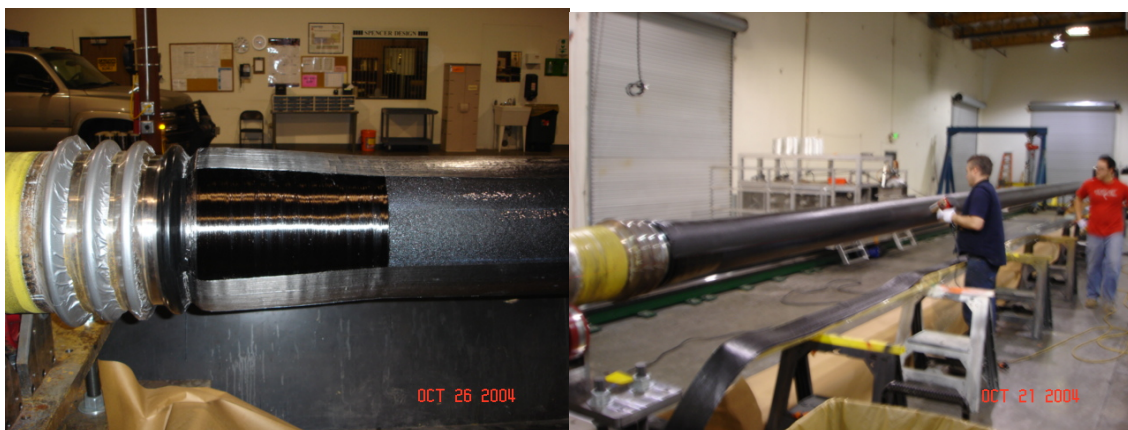


Fig. CPR 45 – Applying Axial Prepreg Strips



Fig. CPR 46 – Hoop Winding over 1st Trap (left)/Hybrid Hoop Layer with Glass (right)

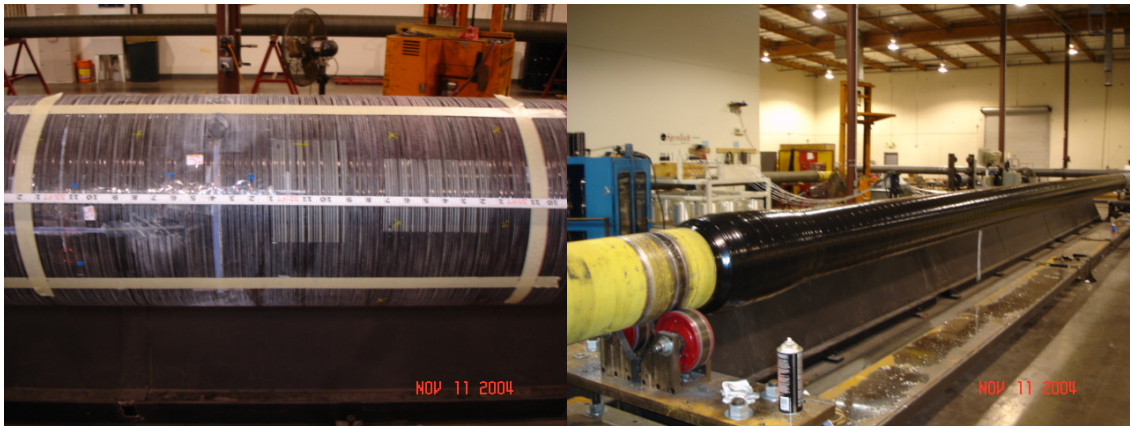


Fig. CPR 47 – Metal Sensors Patches (left)/HNBR Outer Seal (right)

6) Impact Protection – Foam and Polyurea

After final curing, the syntactic impact protection foam, in the form of half-tube sections, is secured in place around the joint. Finally, one last Polyurea layer is sprayed on, from the outboard of one MCI to the other, doubling up the external water seal. This completes the manufacturing process.



Fig. CPR 48 – Installation of Protective Foam



Fig. CPR 49 – Completed Field Joint

16. Field Joints Acceptance Tests

The FAT procedure consisted of the two 11,250 pressure cycles described earlier, and a drift test (with a 16 ft long, 9.5" OD drift).

Three of the five joints passed the FAT and were shipped to Houston. The other two, however, failed in a similar manner: the inner steel liner bulged after depressurization of the bore, indicating a leak through the liner.

One of the failed joints was sectioned off in order to locate the leak. Examination of the bulged area did not reveal any crack or hole. A section from the pin end including the MCI/liner weld, was sent to Matrix Inspection in Houston for further examination. The inner liner weld was scanned again with the ACFM, this time more precisely, with the benefit of being able to manually reach the weld, as opposed to using the remote carrier. The inspection revealed several significant indications, although it could not pinpoint which one might be a full penetration crack. The composite and secondary liner were subsequently stripped off and the area around the girth weld cut in four longitudinal sections. They were scanned once again, revealing the same indications. A wet mag test revealed two full penetration cracks, one of which had been completely missed by the ACFM.

Meanwhile, the other failed joint was repressurized in an attempt to locate the inner liner leak. In doing so, the joint started leaking to the outside, throwing into question the integrity of the secondary (steel liner) and tertiary (Polyurea liner and seal) pressure barriers. This prompted further examination of the three joints already delivered in Houston. A high definition camera was used to look at the inner liner welds again, although inconclusively (as noted before, the inside of the welds have too much relief to properly distinguish cracks), although there were suspicious areas. One of the liners was also found to be gouged longitudinally, and the gouge was apparently severe enough to have penetrated the inner liner, as evidenced by the presence of clear water in the previously dried out joint. To explain why this penetration did not cause any problem during FAT, it should be noted that it was a longitudinal crack, similar to those machined in the cracked liner tests, that does not close back during depressurization. The permeable layer was again effective in protecting the liner from buckling. In contrast, a girth weld crack will likely close back during depressurization as the elongation strain is released, trapping the high pressure fluid behind the liner.

One of the two remaining joints was then pressured up to 14,000 psi to induce an axial load higher than any potential operating condition, in order to determine if the joint might still be suitable for field installation. Unfortunately, a slow pressure loss was observed at 14,000 psi, and, after releasing the pressure, another liner bulge was found. At this stage, it was decided not to deliver the last joint to the Magnolia Project, due to lack of confidence in the steel liners pressure integrity.

Samples of failed liner/MCI welds were sent to DNV for analysis, along with similar, but unfailed, samples taken from the TS-5A test joint (burst test). The analysis included visual and microscopic examination, chemical composition and hardness tests. DNV concluded that several lack of fusion type defects were present in the field joint samples. The only defect that was noted on the test joint samples was a weld undercut.

RECOMMENDATIONS FOR FURTHER COMPOSITE RISER DEVELOPMENT

Although the composite riser joints could not be installed on Magnolia in a timely manner, this project has nevertheless achieved a number of important results in progressing the technology toward a full field development application:

- 1) A Finite Element Analysis (FEA) model has been developed and validated to the point it can now be readily used as a design tool for future composite riser applications.
- 2) A new composite fiber lay-up design has been developed and demonstrated to increase axial load capacity by 40% over those used in previous projects, using the same metal part geometry and axial fiber thickness.
- 3) A system to monitor the performance of the composite material in service has been qualified and can be made available for offshore deployment within the time frame of a future project.
- 4) A large amount of test data has been collected, leading to a better understanding of stress distributions between structural composite and steel components.

For a future composite riser project, the following recommendations should be considered:

1) Secondary Pressure Barrier Requirement

This requirement originated out of concerns for potential penetration of the inner steel liner due to drilling tools gouging, in the absence of an in-service early leak detection method. Providing this backup has been a major design, fabrication and quality control complication. A rubber liner seal has been shown to be too vulnerable to jetting action in the event of a high pressure leak through the steel liner. A secondary steel liner pressure integrity has been difficult to verify. Given the configuration of the double barrier, NDE methods for 100% defect detection are limited, and neither barrier can be independently pressure tested. The secondary barrier also introduces an additional hazard in the form of potential buckling of the inner liner (ref. cracked liner tests).

Elimination of this requirement would remove a large number of the challenges encountered in the course of this project. This may be achieved by using a steel liner thick enough to prevent through-wall gouging, albeit a weight penalty would be incurred. This approach would be helped by development premises that minimize the need for through-production riser interventions (limited to running or pulling tubing; using a dedicated drilling/workover riser;...). A logging tool capable of detecting small cracks in the liner may also have to be developed.

2) Liner Welding

This project clearly illustrated the criticality of obtaining liner girth welds that are 100% reliable and inspectable. In order to achieve this goal, the following is suggested:

- a. Include metallurgical, welding, sealing and inspection experts in the Project Team from the start.
- b. Optimize the compatibility of the liner material to the end connector forgings, and make adequate procurement schedule allowance to obtain it.
- c. Use alternative welding methods such as PAW, TIG, friction welding, for more consistent weld quality.
- d. Implement a more automated process for consistent and repeatable weld quality.
- e. Use a thicker wall liner pipe (ref 1) above).
- f. Mill longer pipe sections (50 ft +) to avoid an intermediate girth weld.

An alternative approach would be to eliminate the liner welds altogether, and use mechanical connectors instead. This may require a costly development though, as the connector would have to be qualified for a high working pressure, and demonstrated to be as good as a weld, in order to gain acceptance in a production riser application. Given how thin the liner is, a connector upset will likely be required, making the liner itself more expensive. A threaded connector welded on the liner pipe could be advantageous because, in this case, the weld would be easily accessible from the inside for QC examination purposes.

3) Liner Quality Control

The criticality of the liner welds then brings the issue of a foolproof inspection method. Current NDE techniques fall short of being able to detect lack of fusion defects in welds less than 3/8" thick. A thin pipe inspection method needs to be developed and qualified to detect the smallest acceptable defect, as determined by fracture mechanics. It would be highly desirable that such a technique can be used to also inspect the welds after factory acceptance testing, as was attempted with the ACFM in this project.

Note that a single barrier steel liner would add the comfort of independent leak testing to the full FAT pressure.

4) Composite Manufacturing

The logistics involved with having two different locations for metal and composite manufacturing should be avoided. Not only is the cost high, but the metal assemblies, with their long thin liner welded to heavy end connectors, are very vulnerable to bending. Their handling should be minimized. For a full composite riser project, a single plant doing both metal and composite work is to be favored.

The merits of using prepreg axial mats (in this project) versus helically wound fibers (NIST,...) have been debated. The axial mats may consume less material and lend themselves to a more consistent lay-up in the MCI traps. On the other hand, they result in a significantly more irregular hoop layer geometry due to mat overlap. Whichever method is used, it is important to understand its impact on hoop capacity, which has been shown to be significant in this project. It is important that the FEA model takes this into account.

5) Impact Protection

Whilst the syntactic foam used in this project achieved the required impact protection, it is a fairly expensive solution. The following suggestions are offered:

- a. Verify that the inner steel liner is capable of withstanding the maximum collapse pressure without the external rubber liner seal (i.e., with water pressure applied against the steel liner), and after the joint has been subjected to impact test. This would alleviate the concern about potential damage to the external rubber liner.
- b. In the case of a full composite riser deployment, the impact energy criteria may be lowered through the use of composite-friendly handling equipment and procedures (as is the case when running Chrome tubulars for instance).
- c. Comparing this project to others, it appears that hybrid (glass/Carbon) hoop layers significantly alter the joint impact resistance, although this influence is not fully understood. Additional impact tests on various hybrid configurations should be undertaken to determine the optimal solution. Helical winding of axial fibers may also improve impact resistance.

6) Field Handling

This project being premised on running only a limited number of composite joints inserted in a steel riser, the design had to accommodate steel joints running equipment. This has led to additional steel spoolpieces at each end. In a future “all-composite” riser, the end connectors should be machined with internal running tool profiles, so that the joints can be handled on the rig without external elevators.

CLOSE TOLERANCE LINER DRILLING (CTLTD)

With very mature fields, where reserves per well are steadily decreasing, the economic limit will eventually be reached. This was the case in ConocoPhillips' South Texas Lobo Field, and in 2000, the business unit was faced with the dilemma of significantly improving cost performance or abandoning further development of the field. The Lobo asset team explored various ways to find this potential step-change, and Casing Drilling was recognized as a drilling technique that offered this potential.

Casing Drilling is a process whereby the drilling assemblies are not run on drill pipe, but are instead run extending from the end of the casing that will be set at the end of the drilled interval. As such, a casing-drilling rig will not utilize drill pipe at all. The "drill string" is the casing itself.

The anticipated value of Casing Drilling was the elimination of the time required to condition the hole and trip out drill pipe at each casing point. The Lobo wells have 3 or 4 casing strings, so this time could be fairly significant in comparison to the total drilling time. The realized benefits far exceeded this expectation; the casing-drilled wells very seldom experienced the typical drilling challenges found in the Lobo Field.

- The Queen City, notorious for lost circulation problems, became quite manageable.
- In some cases, a casing string has been avoided.
- The mud weights required to control the well are reduced by up to 0.5 ppg.
- Stuck pipe has all but disappeared.

Today, after drilling about 60 wells, there has only been one case of stuck casing, and that did not cause the loss of a well. The casing while drilling rigs are preferentially directed towards the most troublesome areas of the field. The minimum economic field size in Lobo has been reduced significantly, breathing new life into the field.

Taking Casing Drilling Offshore

The onshore application of the Casing Drilling has been highly successful, but the actual cost savings are diminished as the daily spread costs in South Texas are not that great. On the other hand, if similar time-related savings and problem avoidance are applied to the deepwater areas of the Gulf of Mexico, the savings could approach several million dollars per well. This was the rationale used to launch the "Close-tolerance liner drilling" effort.

This effort is targeted towards floating operations in the deeper water Gulf of Mexico. The wells are all subsea, so drilling is never done with casing in the rotary table. Instead, the casing is always run on the drill string, hence the term "liner drilling". Inherent in the deepwater wells is also the need for up to 8 or 9 casing strings, so the "close tolerance" aspect is needed.

ConocoPhillips initiated discussions with several vendors in early 2003 to ascertain the commitment that each was willing to make in delivering liner drilling to Industry. After these discussions, two equipment suppliers were asked to cooperatively develop this technology. The two companies offered expertise that when combined, would develop a technically superior system capable of safely and efficiently drilling the subsea wells.

System Description

The summary basis of design is:

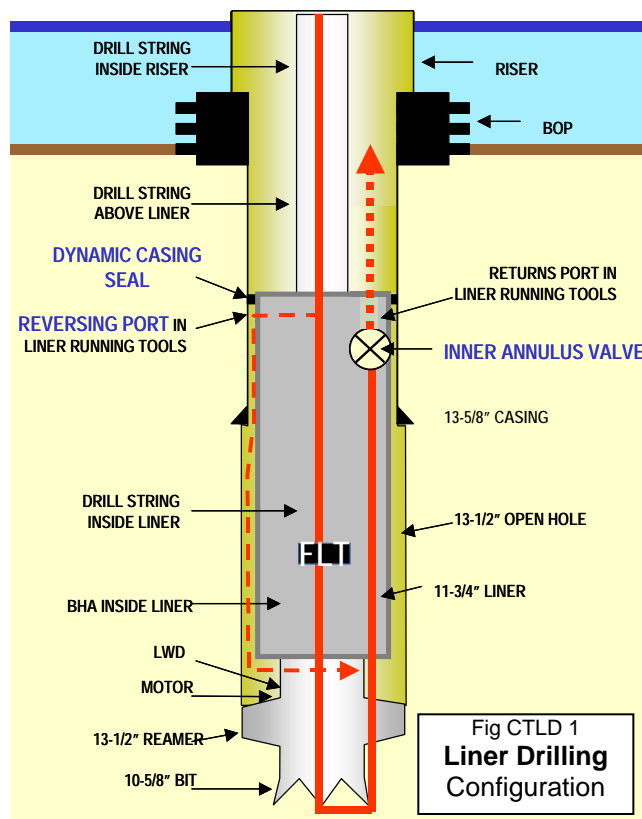
- 11-3/4" OD liner run inside of 13-5/8" casing (12.375" ID).
- 5000' length,
- Setting depths to 25,000',
- Directional drilling capability,
- Formation evaluation (Logging while drilling capability), and
- Synthetic based drilling mud.

The directional drilling and logging while drilling requirements require that the liner have a drilling assembly hanging below it, similar to the way that the onshore casing while drilling is done. The annular clearance between the liner and the casing is so tight, that it would be impossible to circulate mud returns up this annulus without fracturing the exposed formation. Therefore, the design also requires that returns come up the inside of the liner.

Meeting these two broad requirements requires that the drill pipe be run through the liner with the drilling tools hanging below it.

Consequently, the liner is hung from the liner hanger and is not exposed to the drilling torque. Circulation ports were designed into the liner hanger to accommodate the mud returns.

There are two other requirements that impact the design: the desire to sweep the open hole annulus of any cuttings, debris or influx materials, and the need to address a well control incident when the liner and drill string are across the BOP stack. To meet the first



requirement, a reverse-circulation port was built into the liner running tool, and it is ported to divert a small portion of the mud from the drill string down the backside of the liner. This can only be done with the introduction of a seal at the top of the liner hanger that forces the mud to go down the tight annulus rather than directly out above the liner top. This is the “Dynamic Casing SealTM” (DCS) element. To meet the second requirement, an “Inner Annulus ValveTM” (IAV) had to be built into the running tool that allowed rapid closure of the liner by drill pipe annulus when needed. This isolates the drilling riser from the conduit through the liner to the wellbore below the blowout preventer.

Testing:

The new liner drilling system must be exhaustively tested before it will be used offshore. There were three test phases: component testing, cased hole system testing and open hole system testing. The goals for the overall testing program were:

- Prove that the DCS seal integrity is maintained after tripping into the well for 15,000’ and while drilling for the subsequent 5000’. Prove its tolerance to drilling fluids and temperatures used in deepwater drilling applications.
- Prove that the liner hanger and packer can withstand the loads and conditions associated with drilling 5000’. Of significant concern was the internal erosion of the extrudable ball seat, used to set the liner hanger after the drilling was complete.
- Prove that the liner can withstand the cycles associated with rotating for that same duration, even at relatively severe curvatures (doglegs).
- Prove that the IAV and reverse-circulation port and valve maintain their integrity over this duration.
- Understand the unique hydraulics associated with this system. Especially challenging are the surge and swab characteristics of the system.

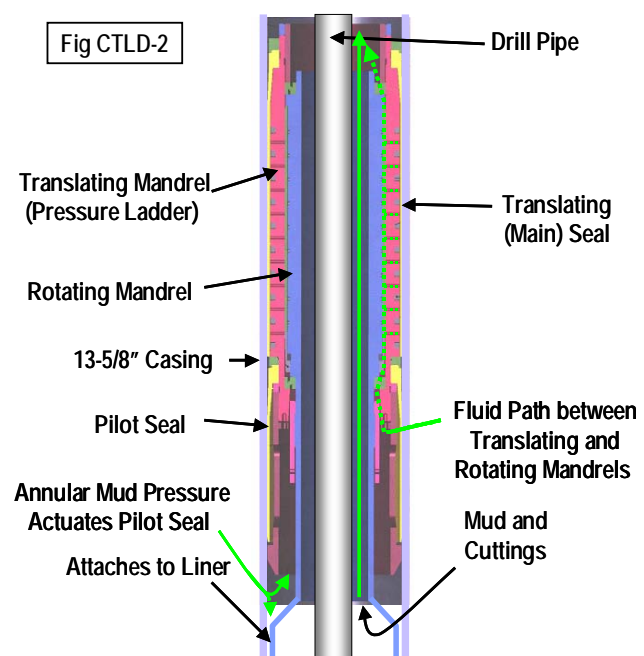
Each of the testing programs and results are discussed.

Component Test Results:

Dynamic Casing Seal:

The DCS is a labyrinth seal consisting of a pressure ladder between a rotating inner mandrel and a stationary outer translating mandrel. The seal element is positioned on the outer mandrel and actuated by the pressure from behind it in the pressure ladder (Fig CTLD-2).

A small-scale seal was built and placed in a casing section and then immersed in a tank with synthetic based mud (Fig



CTLD-3). Mud was circulated through the seal as it was being rotated within the mud. It was found that the seal easily endured the bearing loads and the circulating temperatures to 250° F, at 30 to 90 rpm for 300,000 revolutions. The seal assembly was also tripped up and down the test wellbore for 19,000' to test its wear resistance. Again, the seal performed as designed.

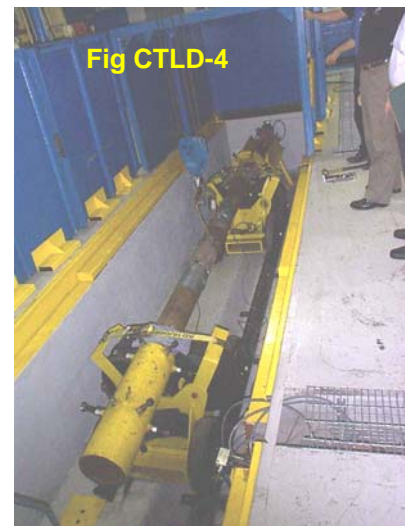


Liner hanger and liner hanger running tool:

The liner hanger used was a modified version of the widely-used Baker INLine™ liner hanger and ZX packer, so extensive component testing was not required. The one component that did require additional testing was the extrudable ball seat. This receptacle is used to catch and seal against a dropped ball in order to shift a sleeve to expose the liner hanger setting tool hydraulics passages. It had not been used in an extended circulation path before, so ball seats made of four different materials were tested in a flow loop where 14.5 ppg water based mud was circulated at 500 gpm for 170 hrs. One of the seats showed no significant wear, and it was selected for the new liner hanger running tool.

Liner:

Of concern were the fatigue consequences on the liner while drilling, especially in the connector area. The connectors chosen were flush or near-flush OD: Hunting's SLSF and Grant-Prideco's DWC-DS/A. To test this, a "bouncing betty" was used (Fig CTLD-4). It is an oscillating machine into which pipe can be placed and rotated with induced lateral loads, creating a curvature in the center of the pipe.



Three samples of each connection were tested to failure under an induced stress equivalent to a relatively severe 5°/100' dogleg severity. The samples all failed between 2.7 and 6 million cycles: in all cases, at least 10 times the goal. Both were deemed acceptable for use offshore.

Cased Hole Testing:

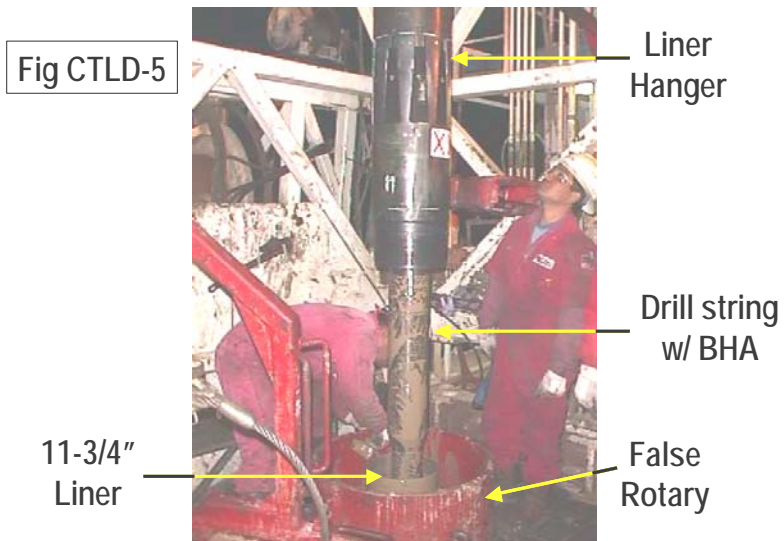
Upon successful component testing, the system was assembled and delivered to Tesco's test rig in Houston. The goals of the cased hole testing were:

- Simulate the wear experienced while tripping the assembly into a 19,000' deep well in deep water.
- Simulate the wear experienced while drilling 5000' of open hole.

- Verify the ability of the tools to function after being exposed to the above.
- Test the robustness of the liner connectors for repeated make-up and break-out.
- Determine the vibrational characteristics of the system.
- Understand the hydraulic characteristics of the system.
- Improve the handling procedures for offshore use.

In the cased hole test, the liner was run and hung off in the false rotary. The drilling assembly was run without the concentric reamer or mud motor through the false rotary (Fig CTLD-5).

The liner hanger, liner hanger running tool and DCS assembly were picked up and made up into the liner. The BHA included the downhole drilling dynamics package (CoPilot™ tool) and annular pressure equipped MWD. These devices would be used to measure any vibrations and the pressures necessary to understand the hydraulic characteristics.



The liner drilling assembly was tripped in and a series of pumping, tripping and reaming operations were performed to gather the pressure and vibration information. In all, the system was rotated about 100,000 revolutions, or about 1/3 of an offshore drilling job.

After pulling out the assembly and returning it to the shop, the ball was dropped and the liner hanger set, proving that the mechanism is robust. External inspection indicated no significant wear anywhere (Fig CTLD-6). Upon tear-down, however, there were some negative findings that were addressed. The most significant was the failure of a seal in the liner hanger running tool. This allowed mud into the running tool, and the barite in the mud settled out within the tool, locking up some of the mechanisms (Fig CTLD-7). This was redesigned so that the mechanism was contained in a pressure-balanced oil bath. The DCS seal had several missing wear inserts (Fig CTLD-8), so the shape of these inserts was changed from cylindrical to spherical. The liner was also inspected, and several joints required recutting.

Open Hole Testing:

The redesign and re-manufacturing required about 2-1/2 months. Afterwards, the equipment was remobilized to the Tesco rig, and the open hole testing program began. The objectives of the program were:

- Demonstrate that the system, with its novel circulation path, can drill open hole.
- Determine whether the improvements made to the tools and handling practices were effective.



Mud Filter of DCS

Translating Seal
Of DCS



Liner Hanger
Slips



Fig CTLD-6



After running the 11-3/4" liner in the well, the same BHA was picked up and run through the liner as in the cased hole test, except that the specially developed 13.5" Smith Rhino Reamer and a mud motor were picked up to allow the hole enlargement for the liner at relatively low

liner rotation speeds. The liner hanger running tool, liner hanger and DCS assembly were picked up. (Fig CTLD-9).



The assembly was run into the well and drilling commenced. The first step was to open up the rathole beneath the 13-3/8" casing. When the pumps and rotary were first engaged, there were severe vibrations. Shortly thereafter, metal shavings were found in the shale shaker, confirming that the 13-3/8" casing was about 20' deeper than originally thought and that the Rhino Reamer concentric reamer had been opened too early. The assembly was slacked off to below that and the pumps were re-engaged. The drilling was quite smooth then.

In the following 44 hours, drilling continued to only 2595', some 289' deeper. The penetration rates varied considerably from 100 ft/hr in the sands to 2 ft/hr in the shales. This was due to the extraordinary amount of gumbo that was encountered. The drilling parameters were varied from 30 to 60 rpm, and the pump rates varied from 380 to 520 gal/min. There were numerous drilling problems with blinding the shaker due to too high a flowrate and too many solids. At the end of the day, the gumbo won the fight and the return flow stopped, indicating that the tools had plugged up with gumbo. The assembly was tripped out of the well.

The tools were totally plugged up with gumbo, as expected. The outside of the tools were clean, reinforcing the fact that the reverse circulation feature works in keeping the backside of the liner clean (Fig CTLD-10).

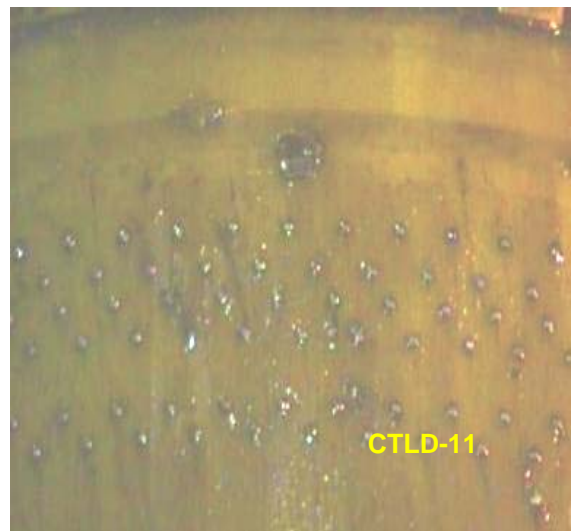


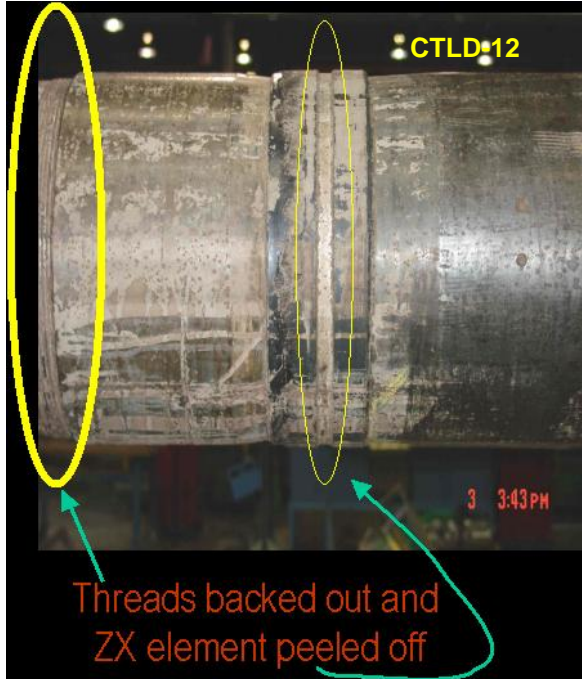
What was surprising is that nearly every shear pin in the running tool had sheared, allowing several sleeves to translate up or down the liner hanger. This was due to the shock loads experienced when the Rhino Reamer was opened up inside of the casing.

The tools were sent to the shop for teardown, but before doing so, the ball was again dropped, and again, the liner hanger set.

Upon examination in the shop environment, the following observations were made:

- The changes to the inserts in the DCS element worked perfectly; none was lost (Fig CTLD-11).
- A ZX seal element had been peeled off through contact with the casing wall. The cause was the translation of the setting cone when the vibrations sheared the set pins (Fig CTLD-12).
- There was erosion on the inside of the outer closing sleeve over the reversing port. This occurred because the vibrations allowed the set pins holding the sleeve in place to vibrate loose, and the sleeve began closing on its own across the reversing jet.





prevent its occurrence.

Post-Mortem Summary:

Though extremely disappointing at the time, it was beneficial that the assembly was subjected to such unusually severe loads and conditions. All of the lessons learned here were much easier to accept than they would have been had the tools performed flawlessly, only to find the same weaknesses in the \$400,000 per day deepwater offshore environment. As it turned out, all of the observations made are easily addressed with minor re-design to avoid their happening again. Additionally, operational practices have been developed which allow extremely rapid detection of a prematurely opening concentric reamer. Further, the gumbo issues in deepwater are virtually non-existent, as synthetic based muds used completely

Hydraulics and Vibrations Analysis:

The data from the Co-Pilot tool was downloaded and analyzed following each of the tests. The hydraulics data collected was used to modify and validate the MI Drilling Fluids Virtual HydraulicsTM modeling software. This software is certainly one of the industry's premiere hydraulics models, and it is widely used by most operators in deepwater. Now, the software can be used to size the reversing jet and accurately predict the hydraulics profiles in the well.

The vibration data was analyzed, and except for the vibrations caused by opening the Rhino Reamer too soon, they were all found to be well within the safe operating limits of the drill string and delicate BHA components.

Drilling Operations and Well Control:

Clearly, the equipment is not beneficial if there are not effective, efficient procedures in place for its safe use. Most importantly are the safety related aspects, and the top of that list is well control assurance. The Inner Annulus Valve was included for the well control case in which the subsea BOP is closed around the liner during a well control event (Fig CTLD-13). By rotating the drill string a few turns to the left, this valve would then be closed, isolating the ID of the liner from the drilling riser.

This valve could not be tested in the cased hole test, as the barite had already settled out in the mechanism and it could not be closed. The modification was made to protect this mechanism between the cased and open hole tests, and the IAV was successfully closed and pressure tested to 200 psi during the open hole test.

From an engineering standpoint, Argonauta Drilling Services, L.L.C., was contracted to perform well control modeling on various kick scenarios. They modeled drilling kicks at 19,193' and 24,193', swabbed kicks behind the liner, swabbed kicks while taken out of the hole and helped develop various well control procedures. To summarize, the well control aspects are essentially the same as for conventional drilling in deepwater.

The operational procedures while drilling are slightly different than from conventional drilling. As examples:

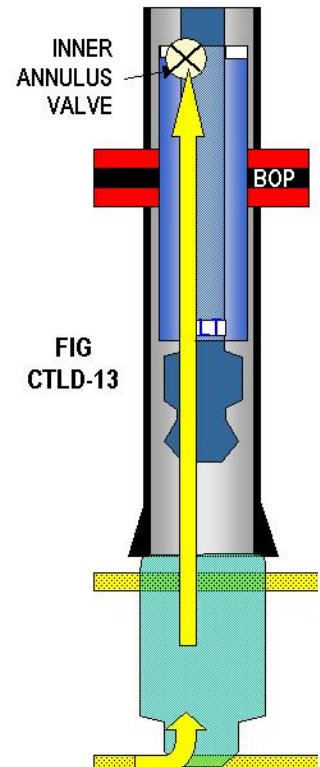
- One must be very careful to control rotary accelerations and decelerations, as the mass and inertia of the liner is quite significant. It was found that several joints of liner broke out at much less torque than they were made up with, and this is due to the momentum of the liner working to break the connections when the liner rotation is being stopped.
- Hydraulics are much more complex due to the fluid being diverted from the drill string at the top of the liner. This must be modeled so that the bit, concentric reamer and reversing jets can all be properly sized. Virtual Hydraulics can now do this.
- The inner drill string and BHA that goes through the liner is run through a false rotary table, which is not conventional equipment on the drilling rig. The mass of this inner string is difficult to handle when the fine threads of the liner hanger are being made up into the top joint of liner. A coarse-threaded "liner saver sub" was designed and built to facilitate that. It worked perfectly.

In short, the procedures are different, but they are not challenging.

Advertising our work:

From the outset, it was not intended that the Close Tolerance Liner Drilling be solely for ConocoPhillips. It was to be developed for the benefit of Industry. As such, a concerted effort was made to keep Industry informed of the progress. Several presentations were made and several articles were written. Among them:

- March, 2003: World Oil Casing Drilling Conference, Houston.
- December, 2003: IADC Gulf of Mexico Conference, Houston.



- December, 2003: Minerals Management Service, New Orleans
- January, 2004: Managed Pressure Drilling Conference, Galveston.
- February, 2004: Natural Gas Technologies Conference II, Phoenix.
- February, 2004: Deepwater Operators Group Meeting, New Orleans
- February, 2004: Drilling Contractor Magazine
- March, 2004: World Oil Casing Drilling Conference, Houston.
- June, 2004: Drilling Engineering Association (Europe), Vienna.

CONCLUSION

The benefits of the subsea separation application are not limited to lower CAPEX costs. Technically, by processing the produced fluids closer to the wellhead, many flow assurance problems such as inefficient multi-phase flow, slugging, hydrates or wax formation, can be significantly reduced. Furthermore, the expected reduction in requirements for large, manned surface facilities should decrease personnel exposure and lead to intrinsically safer operations. The technology is mostly ready for deployment and needs a “first user” to act as a catalyst to wide industry acceptance.

The Composite Production Riser has proven to be more technically challenging than originally expected. However, it is important to note that most of the difficulties encountered are related to matters other than the structural composite (namely, thin steel liner welding and high pressure rubber seal), and can be readily overcome. The project has been highly successful in qualifying the composite structural design for the very high loadings typical of a steel riser. Since a full composite riser string, as opposed to just a few joints inserted in a steel riser, will be much lighter, loading conditions for full field applications will be much lower. This program has removed any outstanding doubt on the applicability of the composite riser technology for deepwater developments.

In early 2004, ConocoPhillips announced the end of its deepwater drilling program and released the Deepwater Pathfinder, the drillship that was completing its long-term contract with the company. With the end of its deepwater efforts came the end of the focus on deepwater technology, as well as further funding of projects like the Close Tolerance Liner Drilling project. However, the sharing of the progress of this project has been extensive, and other operators have shown interest in picking up the work and continuing on. Those discussions are ongoing at this time.